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DEVELOPMENT OF NOVEL EOR METHODS
Foams for Mobility Control in Surfactant Flooding

Topical Report

By
Feliciano M. Llave
J. Michael Sturm
David K. Olsen

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U.S. Department of Energy
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Alex Crawley, Project Manager
Bartlesville Project Office
P.O. Box 1398
Bartlesville, OK 74005

Prepared by
IIT Research Institute
National Institute for Petroleum and Energy Research
P.O. Box 2128
Bartlesville, OK 74005

TABLE OF CONTENTS

TABLES

ILLUSTRATIONS

ILLUSTRATIONS -- Continued

Page

FOAMS FOR MOBILITY CONTROL IN SURFACTANT FLOODING

By Feliciano M. Llave, J. Michael Sturm and David K. Olsen

ABSTRACT

The use of foam as a novel method for mobility control in surfactant flooding was investigated. This report presents an initial evaluation of the potential application of foam as a mobility control agent behind a low concentration surfactant flood. This enhanced oil recovery (EOR) process involves the injection of alternate slugs of gas and surfactant solution as drive fluids behind the active surfactant slug front as an alternative to the use of polymers in order to eliminate unfavorable surfactant-polymer interactions.

Experiments were performed to determine in situ foam generation and propagation using varying concentrations of surfactants in a Berea sandstone core. An apparatus was designed and built to accurately measure differential pressures along sections of the core. The experiments showed that using alternate slug cycles of 0.10 PV (pore volume) of mixed surfactant formulations (as foaming agents) and 0.10 PV of nitrogen gas resulted in the development of significant differential pressures across the core. The differential pressures generated using the mixed surfactant formulation were more significant than the differential pressures generated using the component (individual) surfactants alone, even at relatively low surfactant concentrations. Bottle or shake tests using the various concentrations of surfactants were also performed. The results showed that the foams generated using the mixed surfactant formulations were stable even in the presence of oil. The foam stability was comparable or better than the stability of the foams generated using the individual surfactants. Experiments were also performed to determine the effect of foam flow on reducing mobility and involved steady-state measurement of differential pressures in the presence of foam. Coreflood displacement experiments in the presence of oil were performed using varying concentrations of surfactants to compare various injection modes and oil recovery efficiency. Some of the results of the coreflood experiments showed that the generation and propagation of a foam front through the core, behind a low concentration active surfactant slug, contributed to a significant increase in oil recovery. At a fluid injection rate of one foot per day (1 ft/D), the foam front advanced at a rate of about 0.95 ft/D, indicative of an almost plug flow movement of the foam front.

INTRODUCTION

Surfactant-enhanced waterflooding has been widely used for enhanced oil recovery (EOR). Reservoirs that have been depleted by waterflooding are the primary target for this EOR process. Principally, the surfactant slug is injected to lower the interfacial tension between the water and oil. Lowering the interfacial tension results in more efficient oil displacement and a significant reduction in the oil saturation. The active surfactant slug is then pushed by a drive fluid, which is typically water.

Problems that hinder the efficiency of this process stem from the unfavorable mobility of the slug and the drive fluid with respect to the target oil. Such unfavorable conditions result in the bypassing, dilution, and breakdown of the surfactant slug. To offset such problems, methods for mobility control of surfactant slugs have received increasing attention from the research community. Proposed methods in the literature include the use of polymer-thickened water as the drive fluid.[1]

Foams have been used for EOR applications primarily for their potential in improving oil recovery as well as mobility control. Bond and Holbrook[2] were the first to describe the use of foam to improve oil recovery. They investigated the injection of an aqueous foaming agent slug followed by gas in the formation to generate foam in situ. Fried[3] also studied the injection of foam into porous media which had been previously flooded with conventional gas or water drives. He found that gas could be used to drive a foam bank, which in turn displaced additional oil in the form of an oil bank. Fried attributed the increased oil recovery to the high effective viscosity of the flowing foam. Deming[4] studied the effect of various foam properties on the displacement of liquid. He found that high foam stability favored, but was not necessary, to achieve high displacement efficiency. He also determined that the displacement efficiency was unaffected by the surface tension of the foaming agent solution.

The use of foams to reduce CO_2 mobility was patented by Bernard and Holm.[5-6] They observed that gas permeability in the presence of foam was much less than in the absence of foam when both were measured at the same gas saturations. They also determined that the reduction in permeability was proportionately greater for more permeable sands and sandstones than for less permeable ones.[5] More studies on using foams for mobility control have also been directed towards their use in steam flooding, solvent flooding, and in injection of CO_2 or other gases.[7-13]

This report presents an initial evaluation of the application of foam for mobility control in surfactant flooding. This process involves the injection of alternate slugs of gas and surfactant solution as drive fluids behind the selected active surfactant slug. The idea behind this mobility control method is to generate foam within the porous media in order to provide a reduction in mobility of the surfactant slug. Similar approaches to mobility control have been reported.[14-15]

In this study, experiments were performed to determine the in situ generation of foam using different surfactants in a Berea sandstone core. Accurate differential pressure measurements along the core were used to monitor foam propagation. Tests were also performed to determine the effective mobility reduction due to foam flow. Approximate steady-state differential pressures were measured when pre-generated (generated externally by means of a core plug serving as a foam generator) foam was flowing through the core. Oil recovery coreflood experiments were also performed using specific surfactants to compare different injection modes and to differentiate recovery efficiencies under these different conditions.

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DETERMINATION OF FOAM GENERATION AND PROPAGATION AND MOBILITY REDUCTION DUE TO FOAM FLOW

Experiments were performed to determine foam generation and propagation through the core using varying concentrations of surfactants. Of primary interest in these tests was the screening of candidate surfactants for in situ foaming ability. Another factor of importance was measurement of the apparent reduction in mobility due to the presence of flowing foam. The objective of these tests was to measure mobility and relative mobility during foam flow through the core sample. Bottle or shake tests were also performed to determine rates of foam drainage and ease of foaming at atmospheric pressure.

Experimental Apparatus

An experimental apparatus was designed and built to facilitate determination of foam generation and propagation, as well as determination of mobility reduction in the core due to the presence of foam. The apparatus was also built to provide the capability to perform experiments to determine displacement efficiencies using varying injection modes.

The apparatus consisted of air-driven pumps, high pressure and moderate pressure fluid isolators, a core plug foam generator with an overburden pressure, high-pressure sight glass, a coreholder with intermediate taps, backpressure regulator (BPR) , and differential pressure transducers and transmitters. A schematic diagram of the apparatus is shown in figure 1.

The core used for the experiment was a Berea sandstone of about 750 md permeability. The core was 25.4-cm long with a diameter of 3.81 cm. Characteristics of the core are listed in table 1. The same core was used for all the experiments undertaken in this work. The coreholder was designed with three pressure taps, located at the inlet (7.7 cm from the inlet end of the core), middle (6.0 cm from the inlet tap), and outlet (6.8 cm from the middle tap) sections. These taps provided means to measure differential pressures across sections of the core. The core was potted in lead inside the coreholder to provide a seal for the fluid flow. Cheminert air-driven variable speed pumps were used to inject the displacement fluid (water). This fluid was injected at a known constant rate into the bottom of the floating piston pressure vessels containing the various test fluids.

For the purpose of generating foam before core injection, a 2.54-cm-long core plug (fired Berea) with a permeability of about 1,000 md was used as an external foam generator. The core plug was housed inside a Hassler type coreholder. Simultaneous injection of gas and surfactant resulted in external generation of foam before injection into the core. To facilitate visual observation of foam flow before core injection, a Temco high-pressure sight glass was connected in-line between the core plug assembly and the core inlet. Provisions for recording visual observations using an Olympus boroscope with a video camera/recorder attachment were also provided.

The pressure gradients across sections of the core were accurately measured using two TOBAR Model 75 DPI differential pressure transmitters, with a maximum differential pressure of 2.17 psi (0.15 bars). The maximum operating pressure for these transmitters was 3,375 psig (262.8 bars). Signals from the pressure transmitters were read using two Newport Electronic Model Q2000p differential pressure monitors with a display range of 0 to ±1,999 mV. The inlet pressure connected to the first pressure tap was measured using a Heise pressure gauge with a pressure rating of 200-psig (14.8 bars). Pressure readings were accurate to within ±0.1 psi (0.007 bars). The outlet pressure, before the backpressure regulator (BPR) was measured using a Heise pressure gauge with a pressure rating of 100-psig (7.9 bars). Pressure readings were accurate to within ±0.05 psi (0.0035 bars). A Fisher Recordall Series 5000 dual pen chart recorder was used to monitor the output voltages of the two differential pressure monitors. This set-up allowed for monitoring the trend or progressive changes in the differential pressure across sections of the core. All flow experiments were performed at 100 psig (7.9 bars) backpressure. A Temco backpressure regulator was used to maintain a constant flow at a rated backpressure. This allowed constant flow of effluent fluids from the core while maintaining the selected backpressure. The effluents from the BPR were then collected in burettes to measure fluid production at specified time intervals.

For the bottle or shake tests, graduated pipettes were used to determine rates of foam drainage and ease of foaming at atmospheric pressure. Normal decane was the oil used in the shake tests.

Experimental Procedure

The core and the core plug were vacuum saturated with brine before the actual experiment. The permeability of the core to brine was measured, followed by measurement of the permeability to the surfactant-brine formulation. Accurate measurements of the differential pressure across the core (total length of 12.8 cm from inlet pressure tap to outlet pressure tap) during the fluid flow were used to calculate the permeabilities of the core for the different fluids. As soon as the baseline permeabilities of the brine and surfactant solutions were established, the experiments using the foam were initiated.

In the foam generation and propagation experiments, the fluid permeability measurement step was followed by alternate injection of gas and surfactant at equal slug sizes (0.1 PV slugs each). This alternate injection allowed generation of foam in the core. Changes in differential pressure were recorded to determine foam presence and propagation through the core. Different concentrations of surfactants were tested.

The foam flow experiments to determine mobility involved measurement of differential pressures across the core during a steady-state flow of foam. Continuous external foam generation was needed before injection into the core to ensure approximate steady-state flow of foam. The simultaneous injection of nitrogen gas and surfactant solution into the core plug inlet resulted in external foam generation that was visually observed through the sight glass before injection into the core. The foam generated in the core plug was then injected into the core, and the differential pressures were monitored. Responses of the system due to changes in the total flow rate were observed.

Shake or bottle tests for foams have been widely accepted as a preliminary means of screening surfactants for foaming ability. Although it has been shown that there is no direct correlation between foamability in a bottle shake test and foam formation in porous media, preliminary tests like these provide some idea of the possible interactions between the target oil and the candidate surfactant mixture. For the shake tests, specific quantities of surfactant solution(s) with and without oil were injected into graduated pipettes. The tubes were then sealed and shaken manually with uniform agitation. The heights of the foam and the liquid levels were measured to determine rates of foam drainage for the different surfactants and concentrations tested. These tests were performed at atmospheric pressure. The results of these tests are presented in the following section. These are averages of multiple shake tests (four to five batches) on the same surfactant formulation.

The surfactants used for the experiments (including the coreflood experiments) include GAFOAM-AD, ALIPAL CD-128, AOX16 and Witco TRS 10-410. Alipal CD-128 manufactured by GAF Chemicals Corporation is an ammonium salt of ethoxylated and sulfated decyl and octyl alcohols. GAF Corporation supplies this surfactant as 64% active, containing 14% ethanol and 22% water. Extensive studies have been performed by others to utilize Alipal CD-128 for CO_2 foam flooding. GAFOAM-AD is also manufactured by GAF Corporation. GAFOAM-AD is an ammonium salt of a linear alcohol ethoxysulfate. This surfactant comes from GAF Corporation as 50% active containing ethanol. Alipal CD-128 and GAFOAM-AD were used in this study as foaming agents. AOX16 is a dimethylhexadecylamine oxide surfactant. It was used as the active surfactant slug as well as surfactant additive to possibly help improve the stability of the foam generated using GAFOAM-AD and Alipal CD-128. Isoamyl alcohol was often added to increase the solubility of AOX16 in the surfactant formulation. Witco manufactures TRS 10-410, a petroleum sulfonate surfactant. TRS 10-410 was used as part of the low concentration active surfactant slug formulation for oil mobilization potential.

Experimental Results and Discussion

Foam Generation and Propagation

The permeability of the core to brine and the different surfactants tested are presented in table 2. Table 2 also shows some of the results from the viscosity and surface tension measurements for the various surfactant formulations tested. Results from the experiments to determine in situ foam generation and propagation using the different surfactants and concentrations at 6 ft/D flow rate are shown in table 3. Figure 2 shows a plot of the ratio of the differential pressure of the foam peak and that of the brine (ΔP foam peak/ΔP brine at a flow rate of 6 ft/D) at the surfactant concentrations tested. This figure shows the plot of the ratio of the highest differential pressure developed during foam flow with respect to the average differential pressure when only brine is flowing through the core.

Most of these tests were experiments where baselines of brine (0.5% NaCl) and surfactant-brine solution permeabilities were established before injection of pure nitrogen at 100 psig (7.91 bars). These experiments were performed under conditions where the core was completely saturated with surfactant-brine solution before nitrogen injection. Some of the experiments involved injecting slugs of alternate gas and surfactant to generate foam. Of primary interest in these experiments was the determination of the presence and propagation of foam. The results presented in figure 2 indicated that when the core was fully saturated with surfactant before nitrogen injection, increasing concentrations of surfactant resulted in an increase in the pressure drop across the core with respect to that of the pressure drop when only brine was flowing (ΔP-ratio = ΔP across the core during experiment/ΔP across the core when brine was flowing at the same flow rate). Increasing the concentration from 0.01 to 0.1% resulted in a ΔP-ratio increase from 9 to about 15. Increasing the concentration of GAFOAM-AD resulted in a more pronounced increase in ΔP-ratio than with ALIPAL CD-128.

When using alternate slugs of gas and surfactant, the resulting ΔP-ratios were not significantly greater than brine alone at concentrations less than 0.1% for either surfactant. At a 1% concentration, alternate injection of surfactant and gas slugs resulted in a considerable increase in the ΔP-ratio to about 28. Figure 3 shows a plot of the surface tension versus surfactant concentration. As shown in this figure, the critical micellar concentration (CMC) of the GAFOAM-AD appeared to be greater than 0.1%, such that in order to generate stable foams, the surfactant concentration had to be above 0.1%. This figure supports the results presented when using alternate slugs of the two surfactants and gas.

When using alternate slug injections, it was expected that there would be an insignificant increase in ΔP-ratio at low concentrations of pure surfactants (circa 0.01%), based on the trends presented in figure 2. On the contrary, alternate slug injection of the combination of 0.01% primary surfactant (ALIPAL CD-128 or GAFOAM-AD) and 0.01% AOX16 generated a significant ΔP-ratio compared to the experiments when using slugs of 0.1% of each of the pure surfactants. The experiments using the mixed surfactant formulations seemed to indicate the synergistic effect of the combination of surfactants. The addition of the AOX16 indicated favorable increased stability of the foams generated.

Foam Bottle/Shake Tests

The results of the shake or bottle tests are presented in figures 4 through 7. Figure 4 shows the ratio of the foam height divided by the liquid (fluid) height (cm/cm) versus time (minutes) for different concentrations of AOX16 tested at atmospheric pressure (with air). The results presented indicate that using more concentrated solutions of AOX16 and IAA (0.1% to 0.5%) resulted in a rapid increase in the rate of foam drainage. The presence of alcohol had a negative effect on the foam stability. Figure 5 shows the rate of foam drainage (ratio of foam height / total liquid height) versus time for the same surfactant in the presence of n-decane. The results indicated the same trend of rapid foam drainage as a function of time for both surfactant concentrations in the presence of oil. The addition of oil into the surfactant solution resulted in the formation of a transition layer (oil-brine-surfactant layer) or an emulsion phase. The oil's presence also reduced the amount of the foam generated when the mixture was agitated. The total liquid height used in the ratio calculations included the height of the aqueous phase and the emulsion phase.

Figure 6 shows a plot of the ratio of the foam height/total liquid height vs time using GAFOAM-AD as surfactant. The results indicate a stable foam was generated both with and without added oil. The addition of oil resulted in the formation of an emulsion phase.

Figure 7 presents a plot of the ratio of the foam height/total liquid height vs. time using a combination of GAFOAM-AD and AOX16 as surfactants. The results indicated a stable foam was generated both in the presence and absence of oil (n-decane). The foam layer lasted well beyond the observation time of 5 hours. Foam drainage in the presence of oil was more rapid indicating a negative effect of the oil's presence (a volume ratio of 1:4 for oil:surfactant). The addition of oil also resulted in the formation of an emulsion phase at the brine/oil liquid-liquid interface.

Comparing the surfactant formulations used for the shake tests, the experiments using GAFOAM-AD and GAFOAM-AD with AOX16 showed better foam stability even with the presence of oil compared to using AOX16 alone. The presence of oil significantly reduced the stability of the foam generated in all the shake tests. The experiments using GAFOAM-AD with AOX16 resulted in foam stability that was comparable or even better than the results of the tests when using GAFOAM-AD alone. The results of the in situ foam generation experiments and the bottle tests indicated that the combination of the GAFOAM-AD and AOX16 can generate more stable foams. The addition of the AOX16 seemed to have a positive effect in stabilizing the foam generated.

Steady-State Foam Mobility

Foam mobility experiments were performed on surfactant formulations using AOX16 and GAFOAM-AD. In these tests, varying concentrations of the surfactants in 0.5% and 0.9% NaCl were tested for their resulting mobility in the core upon foam generation at a fixed foam quality (gas injection rate/total fluid injection rate). The results are presented in table 4 for the different concentrations and injection rates tested. The results include the calculated mobility of the foam and the relative mobility of the foam with respect to brine, $\lambda_r = \lambda / k_{brine}$ (cp^{-1}), based on the approximate steady-state pressure gradients due to the foam flow in the core. Figure 8 shows the relative mobility of the foam at the different concentrations of surfactants as a function of the calculated frontal velocity. A summary of the results showed some similarity with observations by Heller[12] who investigated the use of foams for mobility control of CO_2

floods. The results indicated an almost linear dependence of the relative mobility on the flow rate over the ranges tested for the cases using AOX16. Higher injection rates resulted in higher mobility. Sight glass observations during the AOX16 tests though, did not indicate foam generation before and after the core. The experiments using AOX16 may not have generated foam in the core. The relative mobility measured may possibly be that of a liquid and not a foam. On the other hand, the results of the GAFOAM AD showed a rapidly decreasing non-linear dependence of the relative mobility of the flow rate, at rates above 10 ft/D. These results indicated that the foams generated (confirmed by sight glass observations of inlet and outlet foam generation) using GAFOAM-AD would not propagate as fast through the core at a similar liquid flow rate. Comparing the results for the two surfactants tested, at 10 ft/D, the relative mobility would be about 0.15 cp^{-1} (or an effective viscosity of 6.7 cp) for both surfactants tested. Increasing the injection rate to about 20 ft/D, the relative mobility of the GAFOAM-AD foam would still be about 0.15 cp^{-1} (or an effective viscosity of 6.7 cp) while that of the AOX16 test would be about 0.3 cp^{-1} (or an effective viscosity of about 3.33 cp). Higher injection rates would further increase the difference in the relative mobility of the two systems tested. The results of this study also showed that relative mobility also decreases with an increase in surfactant concentration in the case of AOX16. Comparing these results with the foam stability tests, the relative mobility is not a direct function of foam stability.

These mobility experiments provided some insight regarding the range of injection rates where reasonable or desired frontal mobility is achievable, depending on the specific EOR method desired. Heller[12] cited a relative mobility reduction from 20 cp^{-1} for unfoamed CO_2 to a range between 0.1 and 0.5 cp^{-1} as an acceptable relative mobility for CO_2 flooding applications. Reduction of relative mobility to ranges less than 0.1 cp^{-1} would result in a condition where profile modification occurs rather than mobility control. Similar values for the mobility ranges would be applicable for targeting mobility control of surfactant flooding.

COREFLOOD DISPLACEMENT EXPERIMENTS

Coreflooding experiments were performed to investigate the effectiveness of the use of foams in improving the oil recovery potential of low concentrations surfactant floods. For this purpose, a series of low concentration oil recovery experiments were performed in order to compare displacement efficiencies under different injection modes using different surfactant formulations for foaming. The results of these experiments can help to differentiate some of the factors that favor oil displacement efficiency.

Experimental Procedure

A series of oil recovery experiments were performed under gravity stabilized conditions, where the core was vertical and injection was initiated from the top. Common to all the displacement experiments was the condition where the displacement using the surfactant or the foam cycles was at residual oil saturation after waterflood, S_{orw}.

For each displacement experiment, the injection cycle included a core pre-saturation using brine, followed by oil injection, displacing the brine up to the initial oil saturation condition, S_{oi}. Normal-decane was used as the oil for all the coreflood experiments. This oil saturation step was followed by brine injection to displace the oil until a reasonable residual oil saturation was achieved, S_{orw} (after at least 1.2 PV of brine had been injected). The injection modes for the series of experiments that were performed are summarized in figure 9. The experiments used 0.5% and 0.9% NaCl brine for waterflooding, depending on the test conditions. The surfactants used for the experiments included AOX16 with isoamyl alcohol (IAA), Witco TRS 10-410, and GAFOAM-AD. Several experiments using surfactant blends of 0.4% Witco TRS 10-410 + 0.1% AOX16 + 0.5% iso-amyl alcohol in 0.9% NaCl solution and 0.5% GAFOAM-AD + 0.1% AOX16 in 0.9% NaCl solution were performed. The experiments using AOX16 and iso-amyl alcohol alone provided baseline results that can be compared to the experiments using the different surfactant formulations. The alternate injection of gas/surfactant slugs involved 0.05 PV and 0.0125 PV slug cycles. The injection rates selected were principally established at 1 ft/D, based on total core pore volume. This relates back to an approximate fluid injection rate of 0.055 cm^3/min (79.2 cm^3/D) of fluid. Cumulative oil and water production were monitored as well as differential pressures across sections of the core.

Experimental Results and Discussion

A summary of the results of the coreflood displacement experiments is listed in table 5. Figures 10 through 18 show plots of percent oil recovery and water-oil ratio versus pore volumes injected. Some of the figures show the trace of the differential pressure across sections of the core versus pore volume of fluid injected.

Experiment no. 1 involved the injection of a surfactant solution (1.0 PV) after waterflooding. The results of the experiment using 0.1% AOX16 + 0.1% IAA in 0.5% NaCl as the active surfactant slug are presented in figure 10. This figure shows a plot of the percent cumulative oil recovery and water-oil ratio versus pore volumes of fluid injected. The results showed that performing a flood in this mode resulted in negligible improvement in oil displacement after waterflooding. The percent cumulative oil recovered after the surfactant flood was only 48.7% compared to 47.3% after waterflooding. The differential pressures across the core did not show any drastic fluctuations, as expected in the absence of any mobility control agent.

Experiment no. 2 involved injection of an active surfactant slug (0.1 PV) of 0.1% AOX16 + 0.1% IAA in 0.9% NaCl, followed by an alternate slug cycle injection (0.05 PV cycles) of nitrogen gas and surfactant (0.5% AOX16 + 0.5% IAA in 0.9% NaCl). This alternate injection cycle was then followed by simultaneous injection of gas and surfactant at a rate of 2 ft/D, and then at a rate of 1 ft/D. The results of the experiment are presented in figures 11 and 12. The plot of the cumulative oil recovery versus pore volume injected shows a slight increase in oil recovery from 53.6% after waterflood to about 55.3% after the chemical injection (>2.6 PV Injected). This did not clearly represent a significant increase in oil recovery. The plot of the water-oil ratio shows a slight decrease in the slope of water-oil ratio curve, indicative of some flow resistance. The trace of the differential pressures versus pore volume injected indicates that no significant increase in pressure drop in any section of the core developed. The maximum pressure drop of about 0.18 psi occurred in the first section, although no propagation of the pressure peak was observed. Sight glass observations did not show any foam generated after the core plug. Foam was not detected at the outlet end of the core.

Experiment no. 3 involved injection of an active surfactant slug (0.1 PV) of 0.4% Witco TRS 10-410 + 0.1% AOX16 + 0.5% IAA in 0.9% NaCl. This experiment investigated the use of a surfactant blend of petroleum sulfonate and amine oxide-based surfactants. This active surfactant slug injection was followed by an injection of alternate slugs (0.05 PV cycles) of gas and surfactant (0.5% AOX16 + 0.5% IAA in 0.9% NaCl). The injection of alternate slugs of gas and surfactant was then followed a shorter slug cycle of 0.0125 PV, up to a total of 2.0 PV injected. The results of the experiment are presented in figures 13 and 14. The plot of the cumulative oil recovery versus pore volume injected shows an increase in oil recovery from 59.6% after waterflood to about 67.5% after the chemical injection (>2.0 PV Injected). This represented a significant increase in oil recovery (7.9% of OOIP, R_{eff} of 19.5%). Figure 13 shows the sudden increase in oil production during the gas/surfactant slug cycle. The plot of the water-oil ratio also shows a drastic decrease in the slope of water-oil ratio curve, indicative of some increase in oil production. The trace of the differential pressures versus pore volume injected indicate a significant increase in pressure drop that occurred in the second section of the core. The maximum pressure drop that occurred in the first section was about 0.70 psi, while the average pressure drop across the section was about 1.0 psi. No propagation of the pressure peak was observed within first section of the core. The pressure buildup in the second section was indicative of some degree of flow resistance. The sight glass observations did not show any fine bubbles or foam generated after the core plug. The fluid from the outlet of the BPR did not show any signs of foam or emulsion present. The results from this experiment did not clearly indicate whether the increase in oil recovery was attributed to foam generation or not. Bottle tests using the surfactant formulation with n-decane (1:5 ratio of oil to surfactant) resulted in the formation of a milky white dispersion. The increased oil recovery could be directly or indirectly caused by the blocking effect due to the dispersion, as soon as the active surfactant front came in contact with the residual oil.

Experiment no. 4 involved an injection of an active surfactant slug (0.1 PV) of 0.5% GAFOAM-AD + 0.1% AOX16 in 0.9% NaCl. This experiment investigated the use of surfactant blends to develop more stable foams in situ. This active slug was followed by an alternate slug cycle injection (0.0125 PV cycles) of gas and the same surfactant formulation. The alternate injection of slugs of gas and surfactant was then followed by simultaneous injection (1 ft/D) of gas and surfactant up to a total of 3.0 PV injected. The results of the experiment are presented in figures 15 and 16. The plot of the oil recovery versus pore volume injected shows a significant increase in oil recovery from 64.8% after waterflood to about 70.7% after the chemical and foam cycle injection (5.9% of OOIP, R_{eff} of 14.0%). Figure 15 shows the step-increase in oil production occurred during the simultaneous gas and surfactant injection. The plot of the water-oil-ratio also shows a decrease in the slope of water-oil ratio curve, indicative of the occurrence of some flow resistance. The trace of the differential pressures versus pore volume injected for this experiment shows the propagation of the foam front through the entire length of core. The maximum pressure drop that occurred in the first section was about 0.70 psi, while the differential pressure in the second section peaked at about 0.63 psi. Propagation of the pressure peak was clearly observed within each section. At an injection rate of 1.0 ft/D, the foam front advanced at a rate of about 0.96 ft/D, indicative of an almost plug type flow of the foam. Video camera recording of sight glass observations showed continuous fine bubbles or foam generated after the core plug. Fluid from the outlet of the BPR showed a significant amount of foam present in the effluent. The results of this experiment clearly indicate that the increase in oil recovery can be attributed to the foam generation that was observed.

Experiment no. 5 was a combination of the surfactants used in experiments no. 3 and 4. This experiment involved an injection of an active surfactant slug (0.1 PV) of 0.4% Witco TRS 10-410 + 0.1% AOX16 + 0.5% IAA in 0.9% NaCl. This experiment, like experiment no. 3, investigated the use of a surfactant blend of petroleum sulfonate and amine oxide-based surfactants. This active surfactant slug injection was followed by simultaneous injection of gas and a surfactant blend of 0.5% GAFOAM-AD + 0.1% AOX16 in 0.9% NaCl. The results of the experiment are presented in figures 17 and 18. The plot of the cumulative oil recovery versus pore volume injected shows a significant increase in oil recovery from 50.6% after waterflood to about 57.5% after the chemical and foam cycle injection (6.9% of OOIP, R_{eff} of 16.2%). Figure 17 shows the increase in oil production occurred during the simultaneous gas and surfactant injection. The plot of the water-oil ratio also shows a step-function in the rate of water-to-oil production, indicative of the occurrence of some flow resistance. The trace of the differential pressures versus pore volume injected for this experiment shows the propagation of a displacing front through the entire length of core. The maximum pressure drop that occurred in the first section was about 0.58 psi, while the differential pressure in the second section peaked at about 0.41 psi. Propagation of the pressure peak was observed within each section. At an injection rate of 1.0 ft/D, the front advanced at a rate of about 0.48 ft/D in the first section and about 0.43 ft/D in the second section. Sight glass observations showed discontinuous streaks of foam generated after the core plug. The foam streaks observed were not of the same fine and continuous form that was observed in experiment no. 4. Fluid from the outlet of the BPR showed some foam in the effluent. The results of this experiment indicate that the increase in oil recovery can be attributed to the possible combined effect of the injection of the active surfactant blend and the foam generation. The overall low oil recovery for all the coreflood experiments is not indicative of an optimized system.

CONCLUSIONS

The following conclusions are drawn from the results of the different experiments:

Foam Generation and Propagation Experiment

1. Increasing the surfactant concentration results in an increase in the ΔP-ratio (pressure drop in the presence of foam / pressure drop when only brine was flowing) in the core. This is at a condition where the core is completely saturated with the surfactant before nitrogen is injected.

2. Concentrations of surfactant greater than 0.1% were required to generate stable foam when alternate 0.1 PV cycles of nitrogen gas and surfactant are injected into a brine-saturated core.

3. The use of mixed surfactant formulations, GAFOAM-AD with an amine oxide surfactant, AOX16 or ALIPAL CD-128 with AOX16, results in the development of significant pressure gradients across the core. These significant differential pressures are detectable when alternate slug cycles of 0.10 PV of nitrogen gas and 0.10 PV of surfactant are injected into a brine-saturated core, even at a low concentration of 0.01%.

4. The addition of a surfactant builder such as AOX16 to a "poor" foaming system shows a positive synergistic effect by improving the foam generation behavior of the overall system. Significant differential pressures can be achieved upon foam generation.

Foam Bottle/Shake Tests

5. Foams generated using GAFOAM-AD with AOX16 are more stable, even in the presence of oil. The presence of the oil drastically reduces the stability of the foam generated in the shake tests. The addition of the AOX16 limits the negative effect of the oil on the foam stability. The foams generated using GAFOAM-AD with AOX16 are better or comparable with the shake tests using GAFOAM-AD alone.

6. Although there is no direct correlation between foamability in bottle/shake tests and in situ, the shake tests provides some visual indication of the interactions possible between the surfactant and the target oil.

Steady-State Foam Mobility Tests

7. There is a strong, almost linear, dependence of relative mobility on the frontal displacement rate for the surfactant AOX16 test (within the flow rate range tested). Experiments using GAFOAM-AD show that there is a rapidly decreasing non-linear dependence of the foam's relative mobility at flow rates higher than 10 ft/D. This indicates that the foams generated using GAFOAM-AD will not propagate through the core as fast as the solution of AOX16, at similar injection rates.

8. The difference in the relative mobility using the two surfactant systems (GAFOAM-AD and AOX16) drastically increases at higher injection rates (greater than 10 ft/D).

9. The relative mobility of the AOX16 tests decreases with increasing surfactant concentration.

Coreflood Displacement Experiments

10. The generation and propagation of a foam front through the core, behind a low concentration active surfactant slug, contributes to a significant increase in oil recovery and provides good mobility control.

11. A stable foam front can propagate through the entire length of core and drive an active surfactant slug. At a fluid injection rate of 1 ft/D, the foam front advanced at a rate of approximately 0.95 ft/D, indicative of an almost plug type of flow.

12. The use of a surfactant formulation of a petroleum sulfonate and an amine oxide as an active surfactant slug, prior to a foam cycle using a surfactant blend, can contribute to mobility control and a corresponding increase in oil recovery. The increase in oil recovery though, cannot be directly attributed to the blocking effect of the dispersion formed due to the active slug or due to the foam's contribution to mobility reduction. The combination of the injection of an active slug of a low concentration surfactant formulation (designed for optimum oil mobilization) followed by a foam drive of alternate slug injections of another surfactant formulation (designed for stable foam generation) and gas appears to have a potential in improving oil recovery.

RECOMMENDATIONS

Additional study in the following areas is recommended:

1. Broaden the class of surfactants that are potential foaming agents.

2. Further investigation of the use of other mixed surfactant formulations is needed to determine their potential for in situ foam generation, mobility control and profile modification. Additional coreflood experiments have to answer the question as to how the foam generation contributes to an increase in overall oil recovery. Flow experiments must be performed in longer cores (2 to 4 ft) to improve the determination of linear foam propagation rates thus limiting the end effects in short cores (< 1 ft long). A 4-ft multiport high pressure, high temperature core flooding apparatus is available for such a purpose. This set-up was assembled as part of the microbial technology development for BE14.

3. Additional study of the use of a surfactant formulation of a petroleum sulfonate and an amine oxide as a low concentration active surfactant slug, followed by a foam cycle using another mixed surfactant formulation is needed. The study should be directed at determining the contribution of each factor to the increase in oil recovery.

4. Further experimental study should also be directed to determine the contribution of the foam in improving the sweep and displacement efficiency. The present study only looks at improving linear displacement efficiency. The increase in oil recovery due to the improvement in sweep efficiency cannot be directly tested in the these experiments. The recovery that will result from the improvement in sweep efficiency in the field application will be significantly higher than the results that this study indicate. The capability to investigate and characterize contributions to improvement in sweep and displacement efficiency should be given attention.

5. Experimental studies on determining foam mobility reduction have to answer the question of how different would the propagation rates be of the foams generated using various potential foaming agents. Further investigation on the experimental effective viscosity would help determine the foam's ability to provide a displacing front that is comparable to that of a polymer-thickened water front.

6. Additional screening studies involving interfacial tension, surface tension and solution viscosity measurements need to be conducted as part of the overall study.

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TABLE 1. - Core characteristics

Berea sandstone core	
Outside diameter, cm	3.81
Length, cm	25.4
Pore volume, cm^3	66.5
Bulk volume, cm^3	289.58
Porosity, %	23.0
Permeability to brine (0.5% NaCl), md	750

TABLE 2. - Properties of brine and surfactant solutions

Solution	Surfactant conc., wt. %	Brine conc., % NaCl	Permeability [1], md	Viscosity, cp	Surface tension, mN/m
Brine	---	0.50	750	1.02	---
Brine	---	0.90	710	1.04	---
ALIPAL CD-128	0.010	0.50	---	1.06	54.0
ALIPAL CD-128	0.050	0.50	760	1.08	36.0
ALIPAL CD-128	0.075	0.50	740	1.12	34.5
ALIPAL CD-128	0.100	0.50	---	1.19	29.0
ALIPAL CD-128	0.500	0.50	---	1.35	28.0
GAFOAM AD	0.010	0.50	---	1.06	56.0
GAFOAM AD	0.050	0.50	800	1.08	44.0
GAFOAM AD	0.075	0.50	780	1.09	39.0
GAFOAM AD	0.100	0.50	815	1.11	36.0
GAFOAM AD	0.500	0.50	---	1.21	31.0
GAFOAM AD	0.010	0.90	---	0.93	---
GAFOAM AD	0.050	0.90	---	0.95	---
GAFOAM AD	0.075	0.90	---	0.97	---
GAFOAM AD	0.100	0.90	---	1.03	---
GAFOAM AD	0.500	0.90	---	1.04	---

TABLE 2. - Properties of brine and surfactant solutions -- Continued

Solution	Surfactant conc., wt. %	Brine conc., % NaCl	Permeability [1], md	Viscosity, cp	Surface tension, mN/m
AOX16+IAA [2]	0.010	0.50	---	1.05	31.5
AOX16+IAA [2]	0.100	0.50	820	1.34	30.0
AOX16+IAA [2]	0.500	0.50	---	9.50	29.5
AOX16+IAA [2]	0.010	0.90	---	1.04	---
AOX16+IAA [2]	0.050	0.90	---	1.09	---
AOX16+IAA [2]	0.100	0.90	---	1.54	---
AOX16+IAA [2]	0.500	0.90	---	20.60	---
ALIPAL CD-128 + AOX16 [2]	0.010	0.50	---	1.25	26.0
GAFOAM AD + AOX16 [2]	0.010	0.50	---	1.23	26.0
0.4% TRS 10-410 + 0.1% AOX16	W/ 0.5% IAA	0.50	---	3.00	29.0
0.04% TRS 10-410 + 0.01% AOX16	W/ 0.05% IAA	0.50	---	1.12	31.0

[1] Permeability across the 12.8 cm section of core where pressure taps were located.
[2] Equal proportion of components, % active by weight.

TABLE 3. - Results of foam generation experiments

Surfactant	Concentration,[1] %	PV Injected	Peak ΔP, psi Inj. Rate: 6 ft/D	Brine ΔP, psi Inj. Rate: 6ft/D	ΔP Foam/ΔP Brine Inj. Rate: 6ft/D
		Nitrogen Injection after Surfactant Saturation			
GAFOAM-AD	0.010	1.00	1.0843	0.1242	8.73
GAFOAM-AD	0.050	1.00	1.4628	0.1242	11.78
GAFOAM-AD	0.075	1.00	1.6807	0.1242	13.53
GAFOAM-AD	0.100	1.00	1.9019	0.1242	15.31
ALIPAL CD-128	0.010	1.00	1.4638	0.1242	11.79
ALIPAL CD-128	0.050	1.00	1.6590	0.1242	13.36
ALIPAL CD-128	0.075	1.00	1.7078	0.1242	13.75
ALIPAL CD-128	0.100	1.00	1.8000	0.1242	14.49
		Cycle of 0.1 PV Nitrogen and Surfactant(s)			
ALIPAL CD-128	0.100	0.10	0.1659	0.1242	1.34
ALIPAL CD-128	1.000	0.10	3.0361	1.1242	24.45
GAFOAM-AD	0.100	0.10	0.2169	0.1242	1.75
GAFOAM-AD	1.000	0.10	3.3994	1.1242	27.37
GAFOAM-AD + AOX16 [2]	0.010	0.10	1.0887	0.1242	8.77
ALIPAL CD-128 + AOX16 [2]	0.010	0.10	1.3467	0.1242	10.84

[1] In 0.5% NaCl brine.
[2] Equal proportion of components, % active by weight.

TABLE 4. - Results of foam mobility tests

Surfactant	Foam quality Q gas/Q total	Q total µL/min	Frontal velocity ft/D	Peak ΔP, psi	Foam mobility[1], $\lambda = (Q/A)/(\Delta P/L)$	$\lambda_r = \lambda/k_{brine}$ cp^{-1}
0.5% AOX16 + 0.5% IAA [2]	50%	660	11.910	1.231	0.1499	0.2055
0.5% AOX16 + 0.5% IAA [2]	50%	1,000	18.045	1.659	0.1686	0.2255
0.5% AOX16 + 0.5% IAA [2]	50%	1,500	27.067	1.373	0.3055	0.4086
0.5% AOX16 + 0.5% IAA [2]	50%	2,250	40.601	1.578	0.3989	0.5335
0.2% AOX16 + 0.2% IAA [2]	50%	1,500	27.067	3.958	0.1060	0.1418
0.2% AOX16 + 0.2% IAA [2]	50%	1,000	18.045	4.554	0.0614	0.0821
0.2% AOX16 + 0.2% IAA [2]	50%	500	9.022	5.855	0.0239	0.0319
0.5% GAFOAM +0.1% AOX16 [3]	50%	110	1.985	0.594	0.0518	0.0693
0.5% GAFOAM +0.1% AOX16 [3]	50%	500	9.022	1.383	0.1012	0.1353
0.5% GAFOAM +0.1% AOX16 [3]	50%	1,000	18.045	2.318	0.1206	0.1614
0.5% GAFOAM +0.1% AOX16 [3]	50%	1,500	27.067	3.253	0.1290	0.1725

[1] Units of darcy/cp.
[2] In 0.5% NaCl brine.
[3] In 0.9% NaCl brine.

TABLE 5. - Results of the coreflood displacement experiments

Injection mode	Cum. PV Inj.	Cum. Oil Rec. , %	WOR [1]	Incremental Rec ,[2]. %	Interfacial tension [3]
Experiment #1					
Waterflood	1.02	47.31	1.90	—	—
Surfactant #1	2.16	48.74	5.35	3.80	[4] 251.0
Alternate injection of N_2 and Surf #2 (0.05 PV cycles)	3.10	49.31	7.44		[5] 100.2
Surfactant #1: 0.1% AOX16 + 0.1% IAA in 0.5% NaCl					
Surfactant #2: 0.5% AOX16 + 0.5% IAA in 0.5% NaCl					
Experiment #2					
Waterflood	1.56	53.57	3.23	—	—
Surfactant #1	1.66	53.8	3.48	3.75	
Alternate injection of N_2 and Surf #2 (0.05 PV cycles)	1.95	54.67	3.85		
Simultaneous injection of N_2 and Surf #2 (2 ft/D)	2.05	54.76	3.94		
Simultaneous injection of N_2 and Surf #2 (1 ft/D)	2.49	55.31	4.15		
Surfactant #1: 0.1% AOX16 + 0.1% IAA in 0.9% NaCl					
Surfactant #2: 0.5% AOX16 + 0.5% IAA in 0.9% NaCl					
Experiment #3					
Waterflood	1.11	59.61	1.68	—	—
Surfactant #1	1.22	61.17	2.37	19.53	[4] 93.5
Alternate injection of N_2 and Surf #2 (0.05 PV cycles)	1.46	66.91	2.56		
Alternate injection of N_2 and Surf #2 (0.0125 PV cycles)	1.80	67.5	2.77		
Surfactant #1: 0.4% Witco TRS 10-410 + 0.5% IAA + 0.1% AOX16 in 0.9% NaCl					
Surfactant #2: 0.5% AOX16 + 0.5% IAA in 0.9% NaCl					

TABLE 5. - Results of the coreflood displacement experiments -- Continued

Injection mode	Cum. PV Inj.	Cum. Oil Rec., %	WOR [1]	Rec_{eff}, [2] %	Interfacial tension [3]
Experiment #4					
Waterflood	1.2	65.96	2.22	---	---
Surfactant #1	1.31	66.16	2.48	13.95	[4] 100.2
Alternate injection of N_2 and Surf #2 (0.0125 PV cycles)	1.46	66.53	2.95		
Simultaneous injection of N_2/Surf #2 (1 ft/D)	2.69	70.71	4.20		
Surfactant #1: 0.5% GAFOAM-AD + 0.1% AOX16 in 0.9% NaCl					
Surfactant #2: 0.5% GAFOAM-AD + 0.1% AOX16 in 0.9% NaCl					
Experiment #5					
Waterflood	1.40	50.58	2.77	---	---
Surfactant #1	1.50	52.19	3.66	16.20	[4] 98.9
Simultaneous injection of N_2 and Surf #2 (1 ft/D)	3.59	57.47	4.89		
Surfactant #1: 0.4% Witco TRS 10-410 + 0.5% IAA + 0.1% AOX16 in 0.9% NaCl					
Surfactant #2: 0.5% GAFOAM-AD + 0.1% AOX16 in 0.9% NaCl					

[1] WOR : Water-oil Ratio.

[2] $$Rec_{eff} = \frac{(S_{orw} - S_{orc})}{S_{orw}} \times 100\,\% = \frac{\text{(Cum. oil recovery after chemical flood - Cum. oil recovery after waterflood)}}{\text{(100 \% - Cum. oil recovery after chemical flood)}} \times 100\,\%$$

[3] Interfacial tension measured by spinning drop interfacial tensiometer, μN/m.

[4] Surfactant #1 with n-decane.

[5] Surfactant #2 with n-decane.

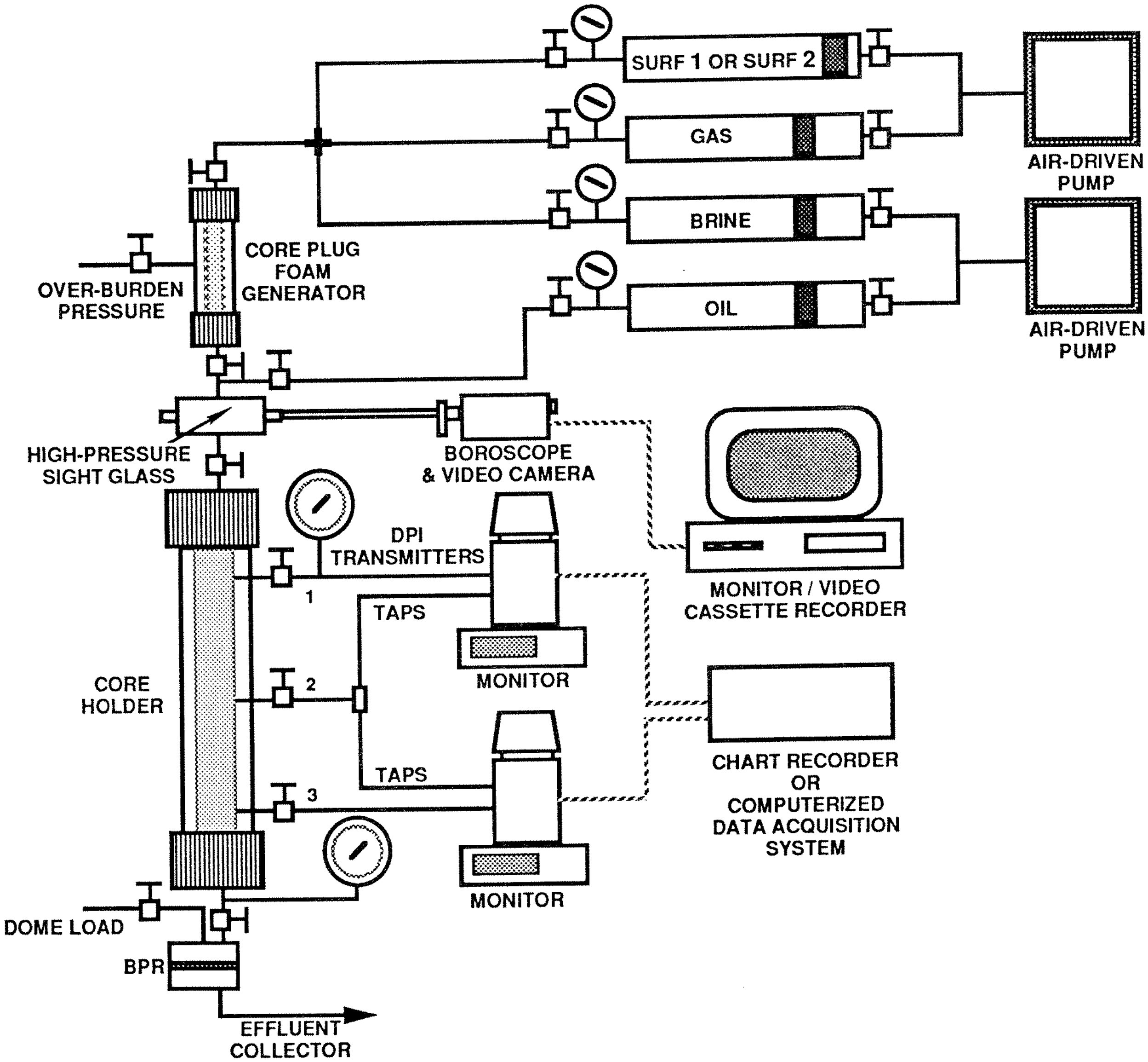

FIGURE 1. - Schematic diagram of experimental apparatus.

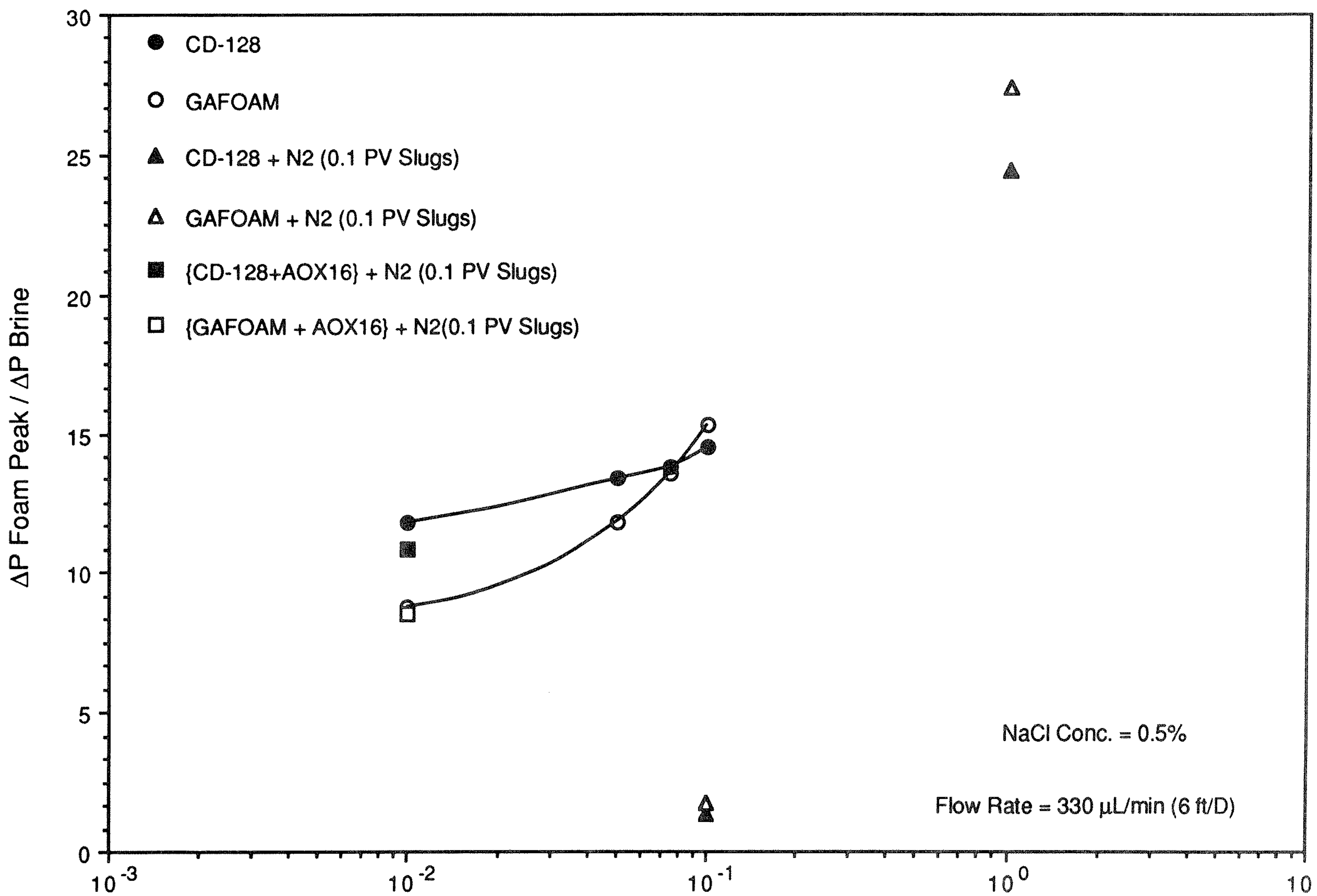

FIGURE 2. - Experimental ΔP-ratio versus surfactant concentration.

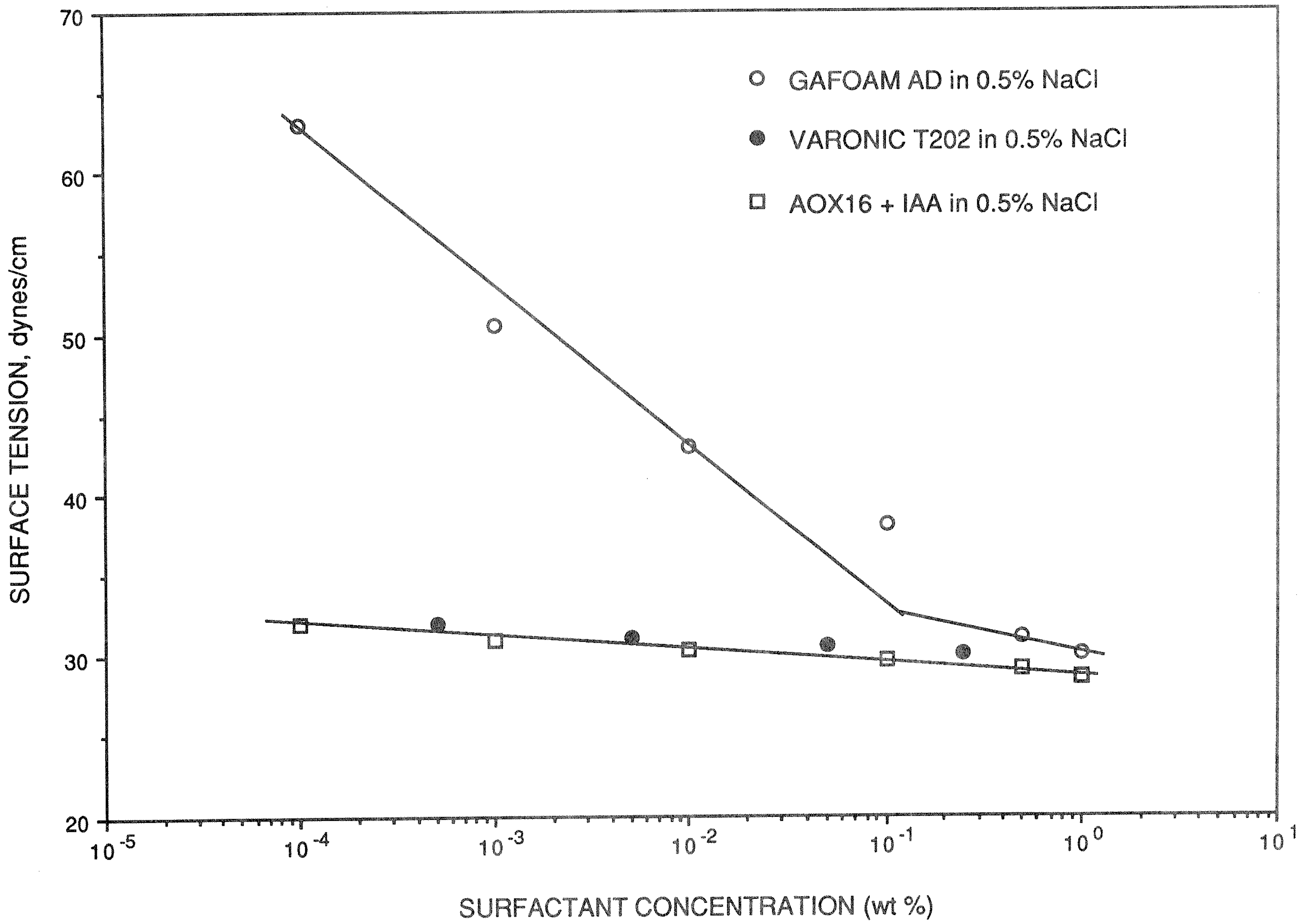

FIGURE 3. - Measured surface tension versus surfactant concentration.

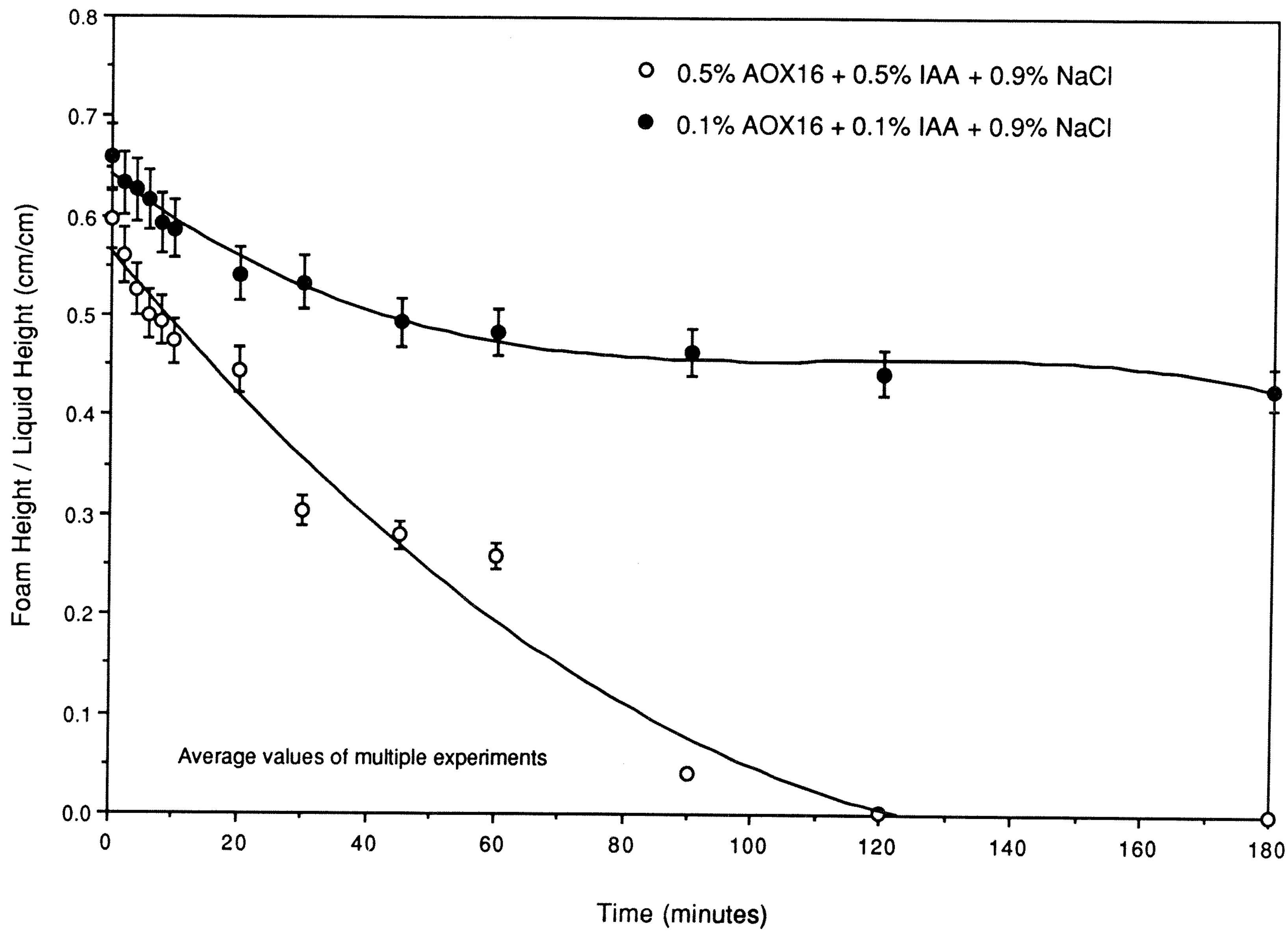

FIGURE 4. - Foam drainage experiment using AOX16 without oil.

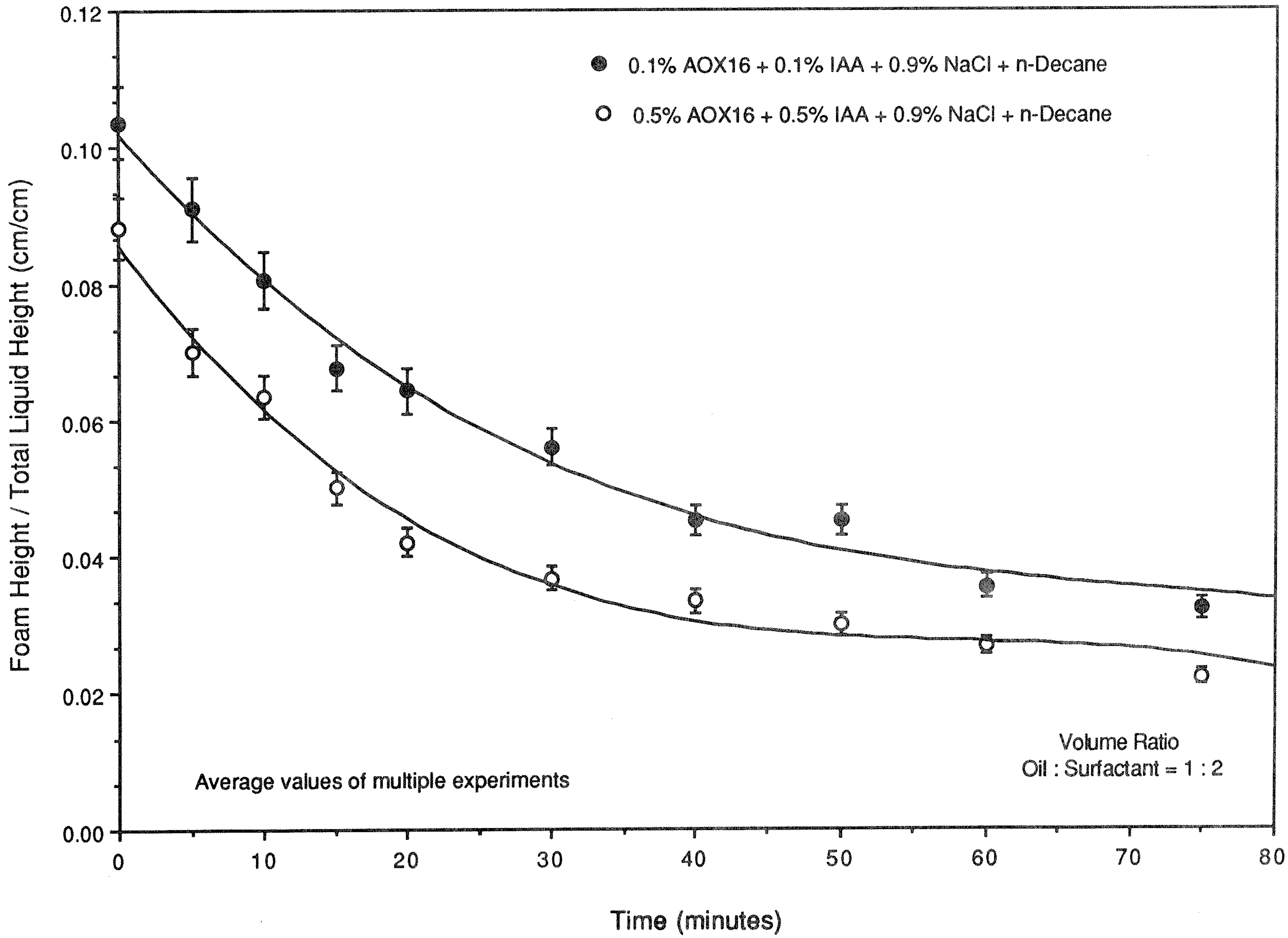

FIGURE 5. - Foam drainage experiment using AOX16 with oil.

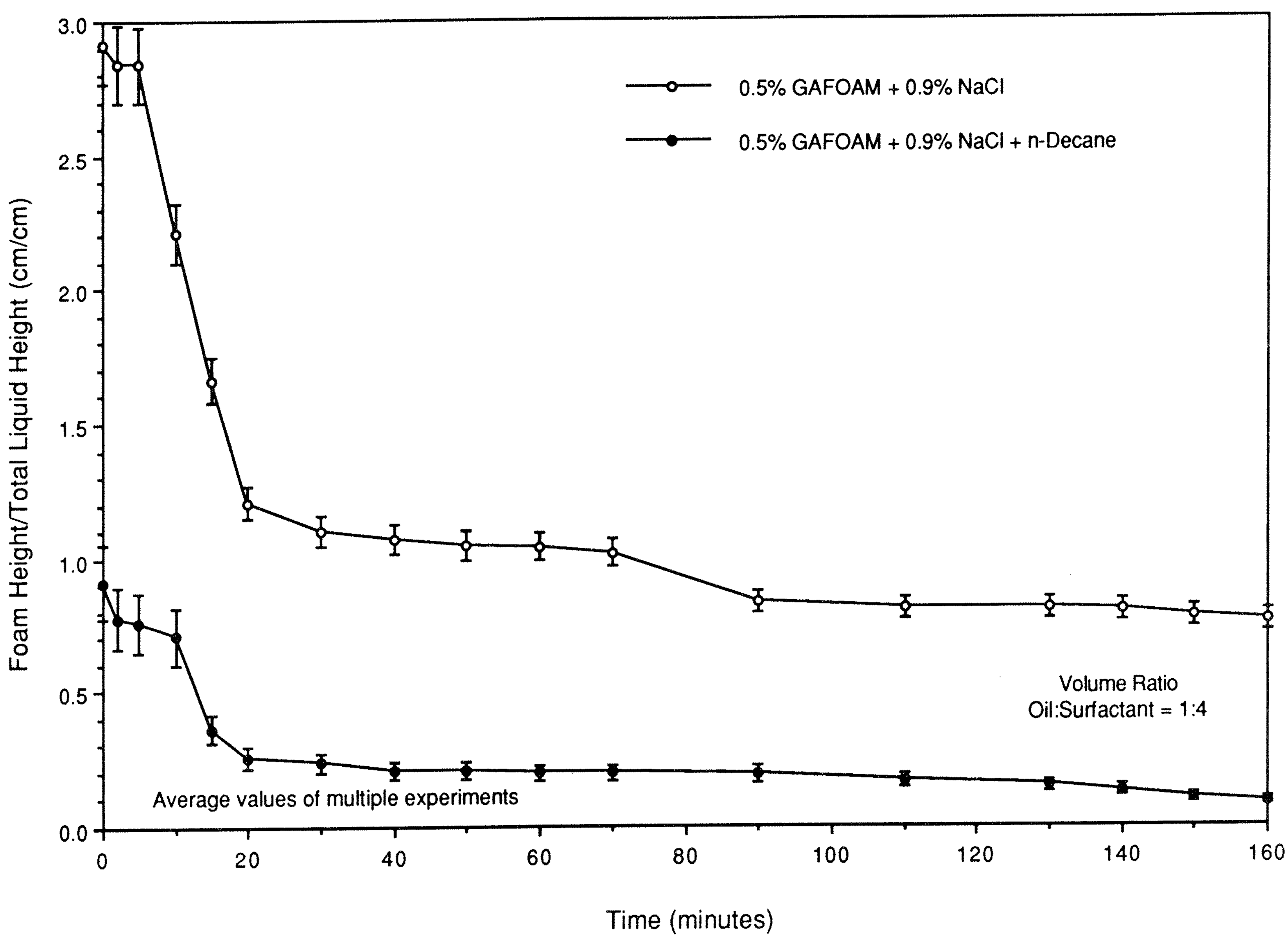

FIGURE 6. - Foam drainage experiment using GAFOAM-AD with and without oil.

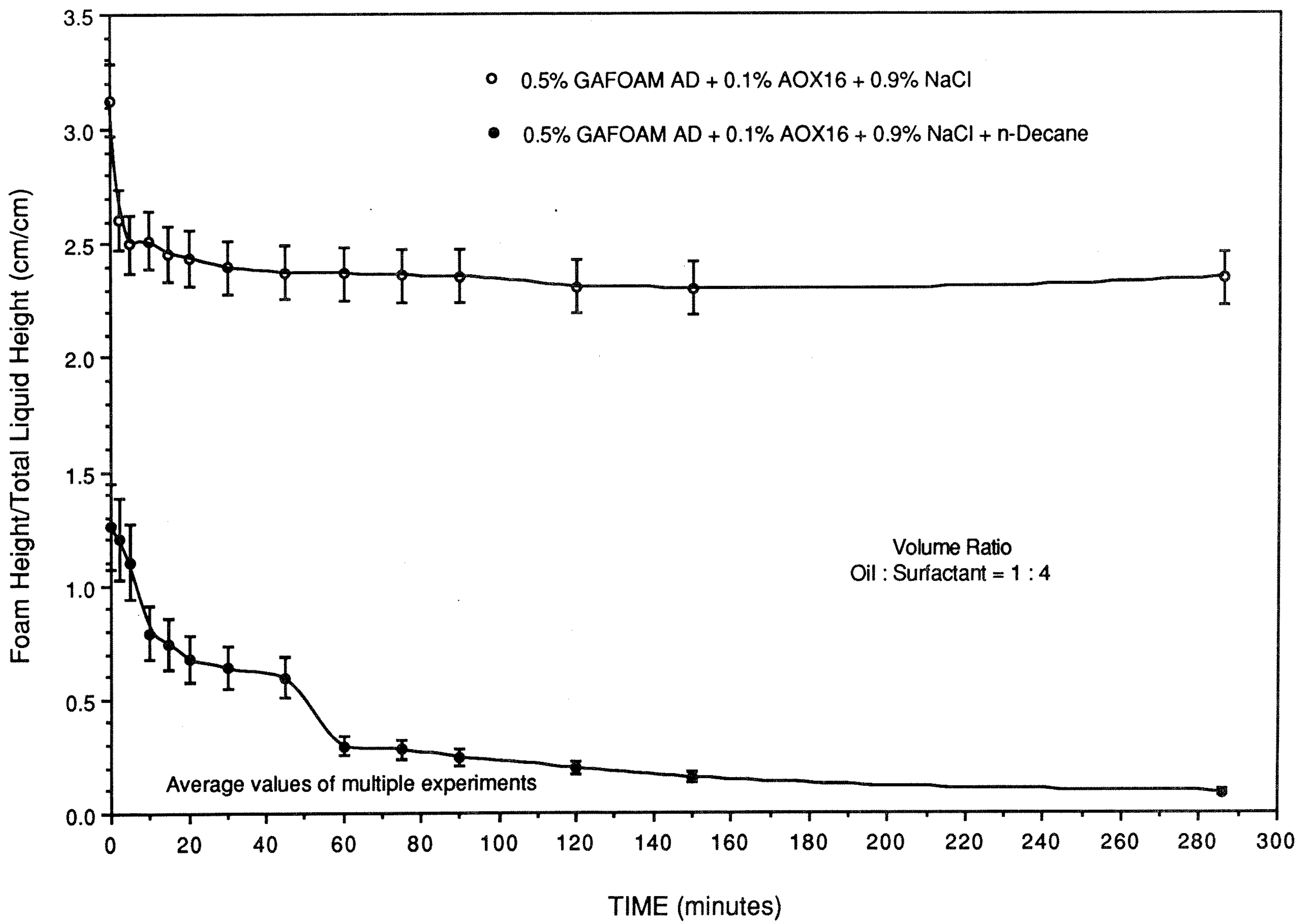

FIGURE 7. - **Foam drainage experiment using GAFOAM-AD + AOX16** with and without **oil.**

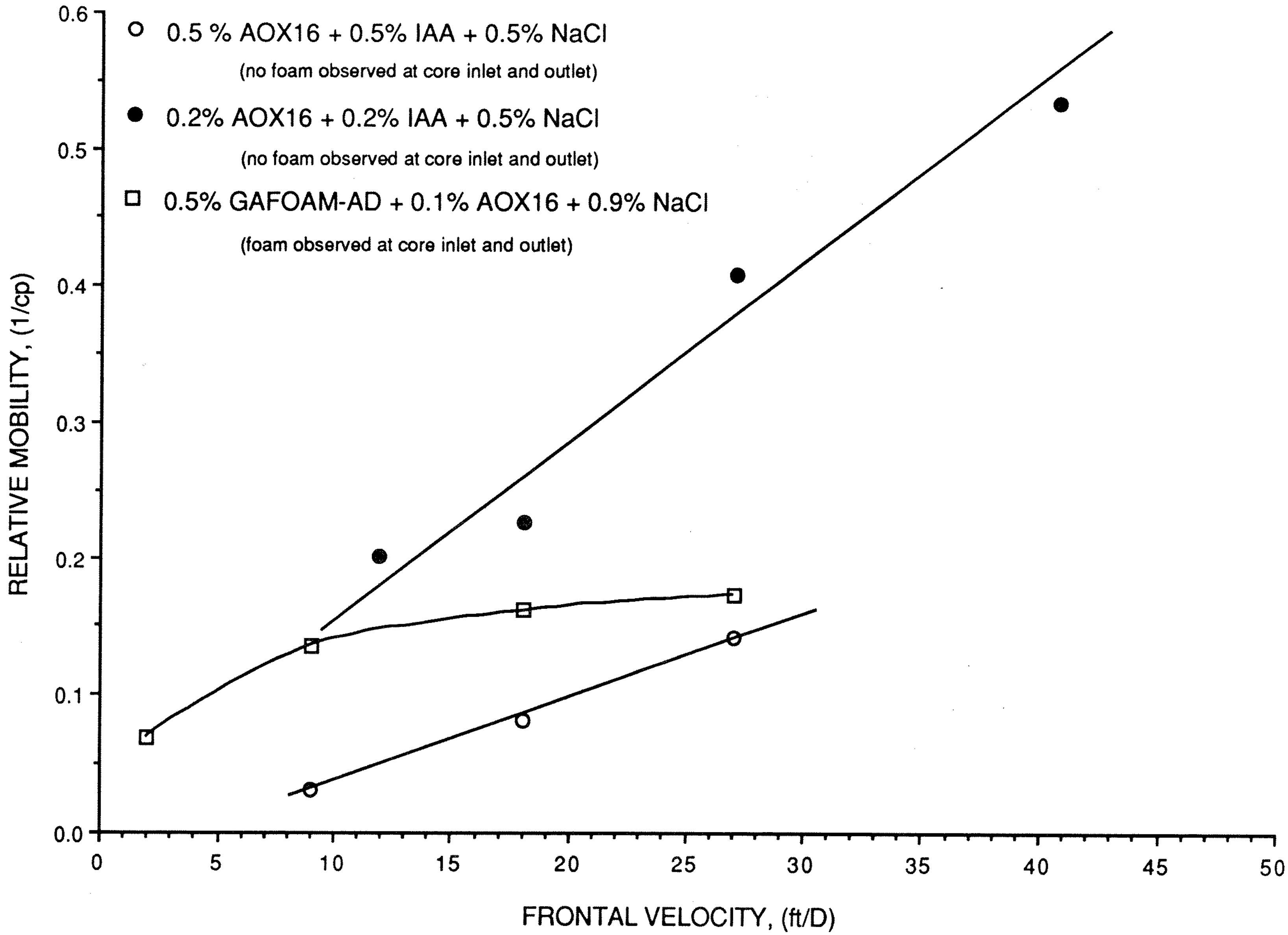

FIGURE 8. - Calculated relative mobility (cp^{-1}) versus frontal velocity (ft/D).

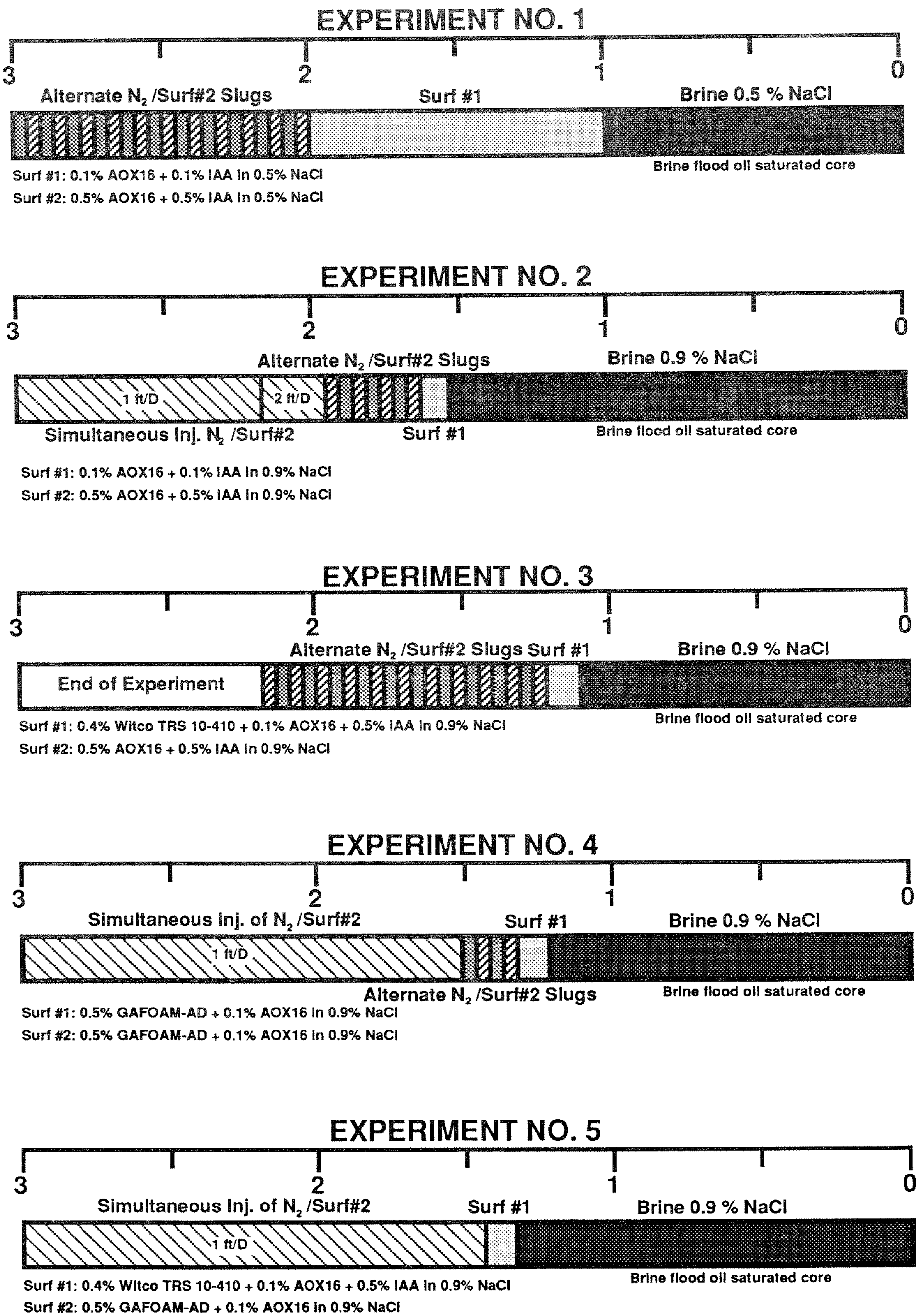

FIGURE 9. - Schematic representation of coreflood displacement experiments.

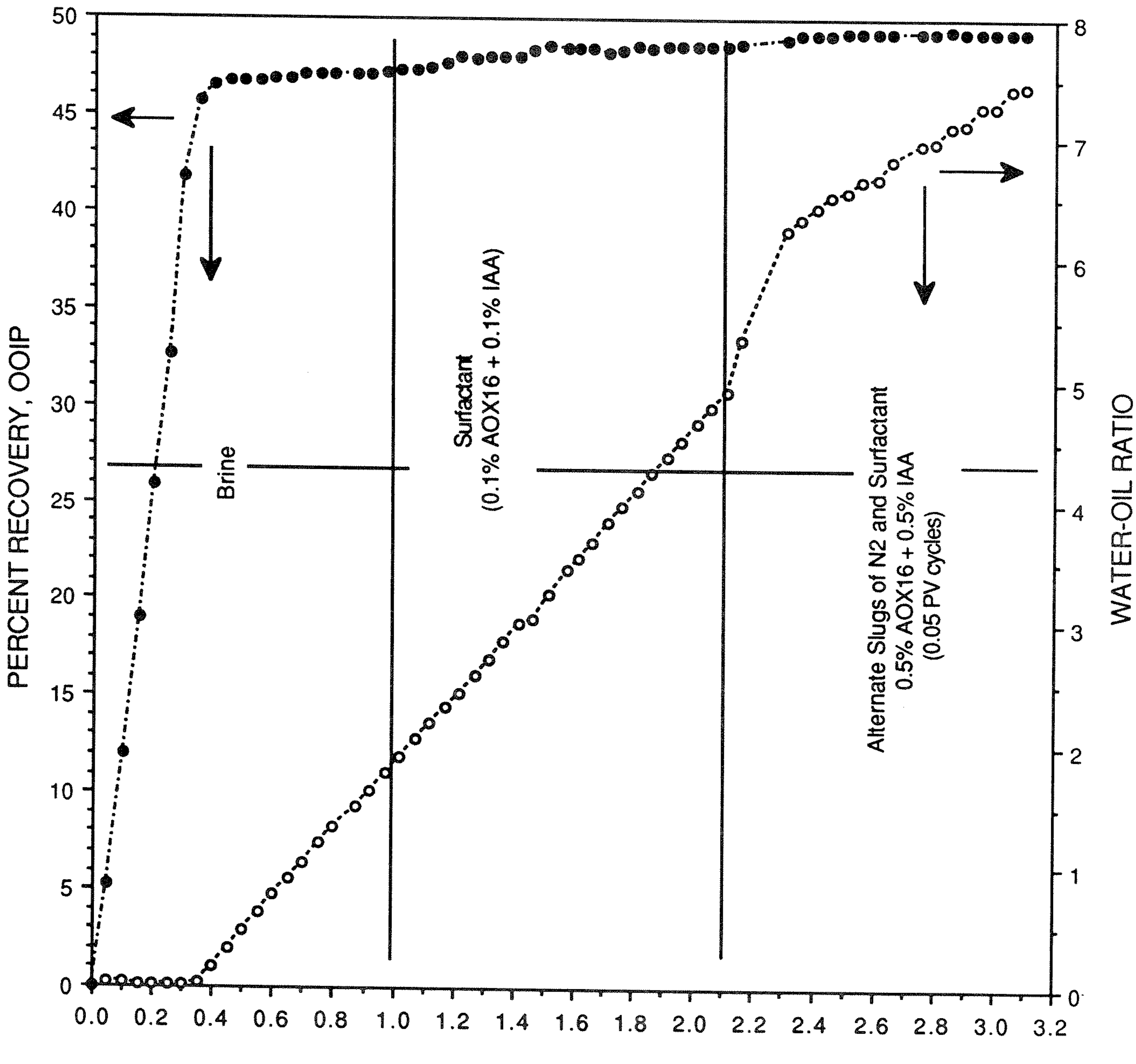

FIGURE 10. - Results of coreflood experiment no. 1.

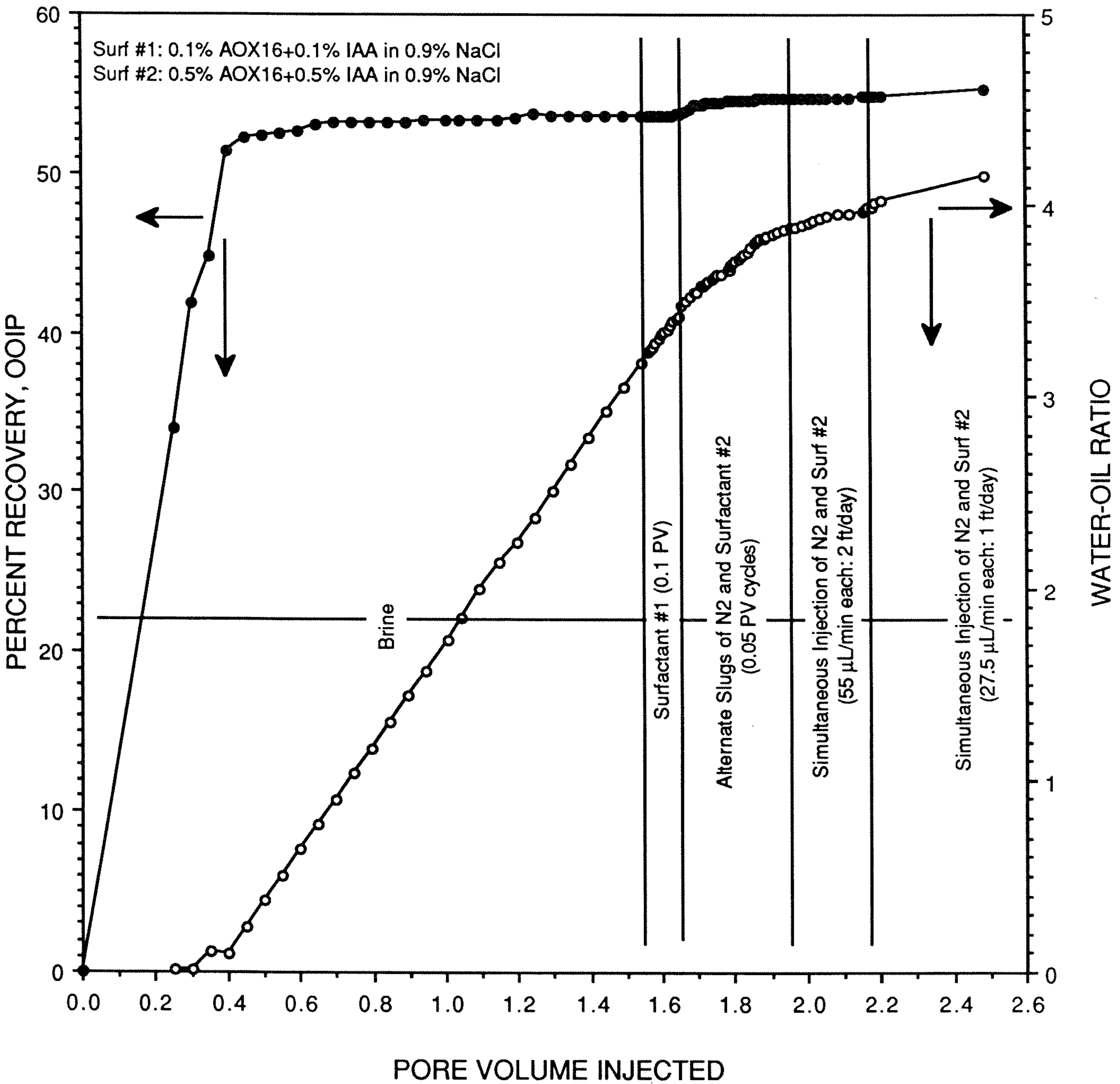

FIGURE 11. - Results of coreflood experiment no. 2.

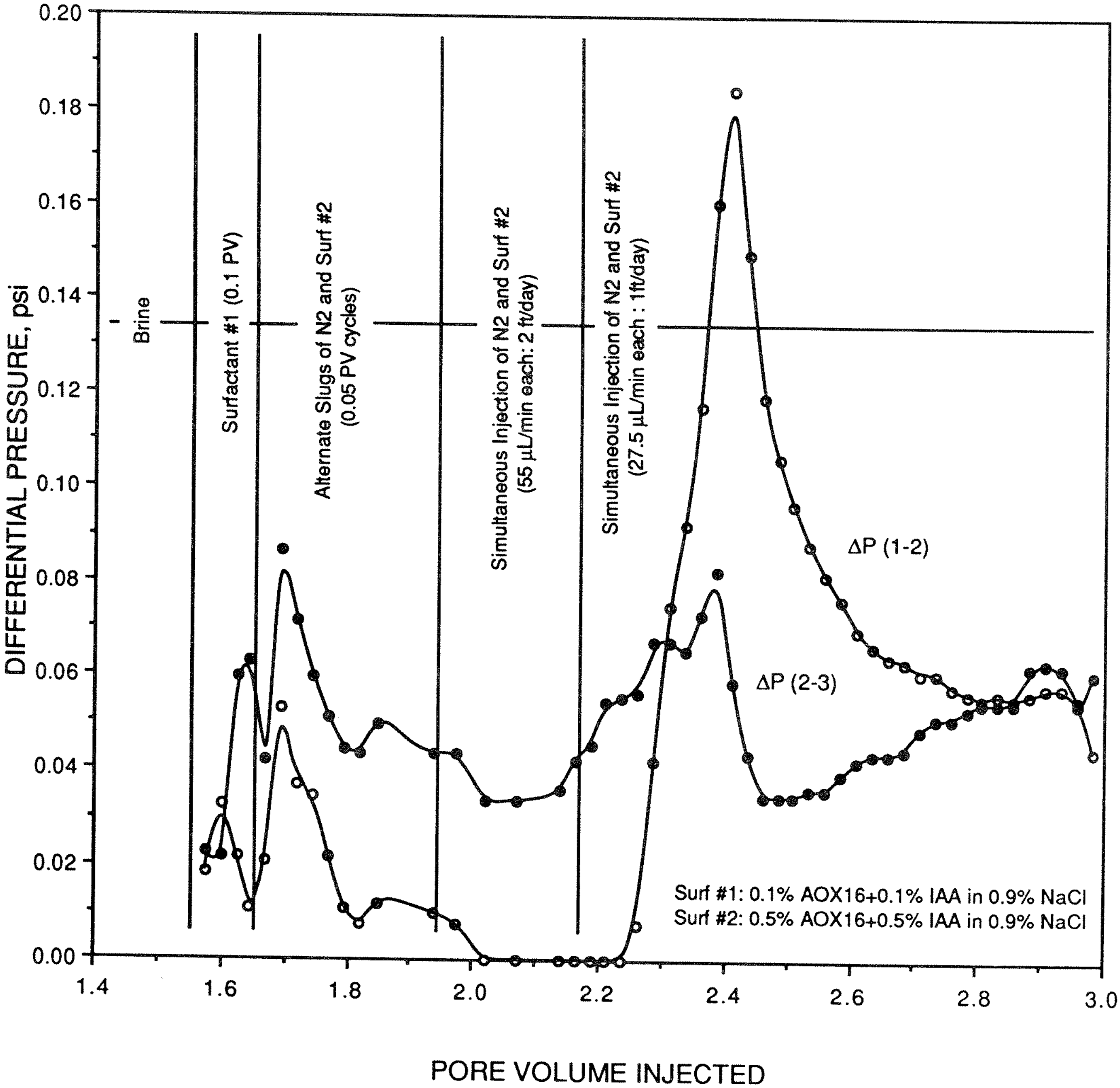

FIGURE 12. - Differential pressure profile of coreflood experiment no. 2.

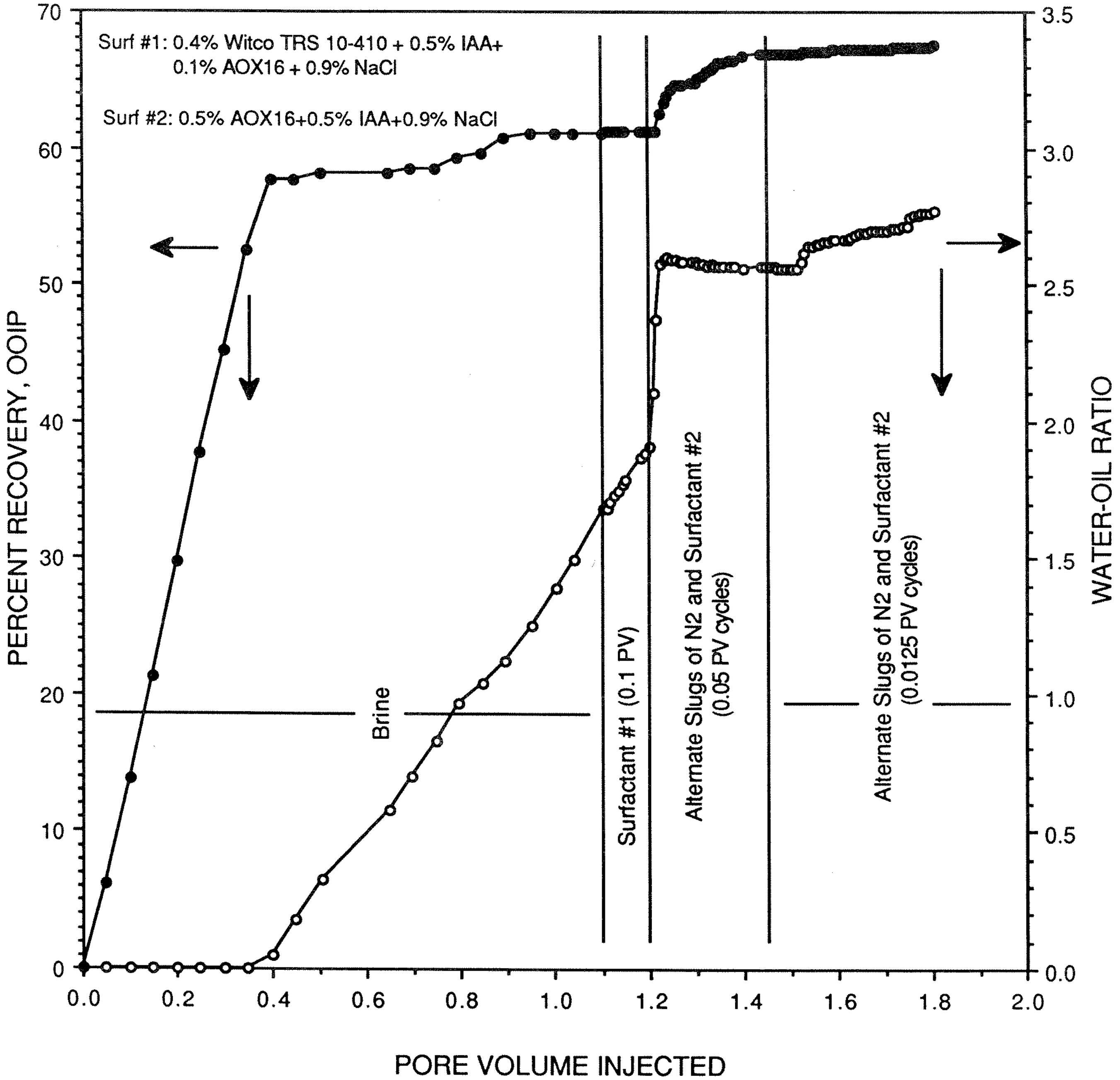

FIGURE 13. - Results of coreflood experiment no. 3.

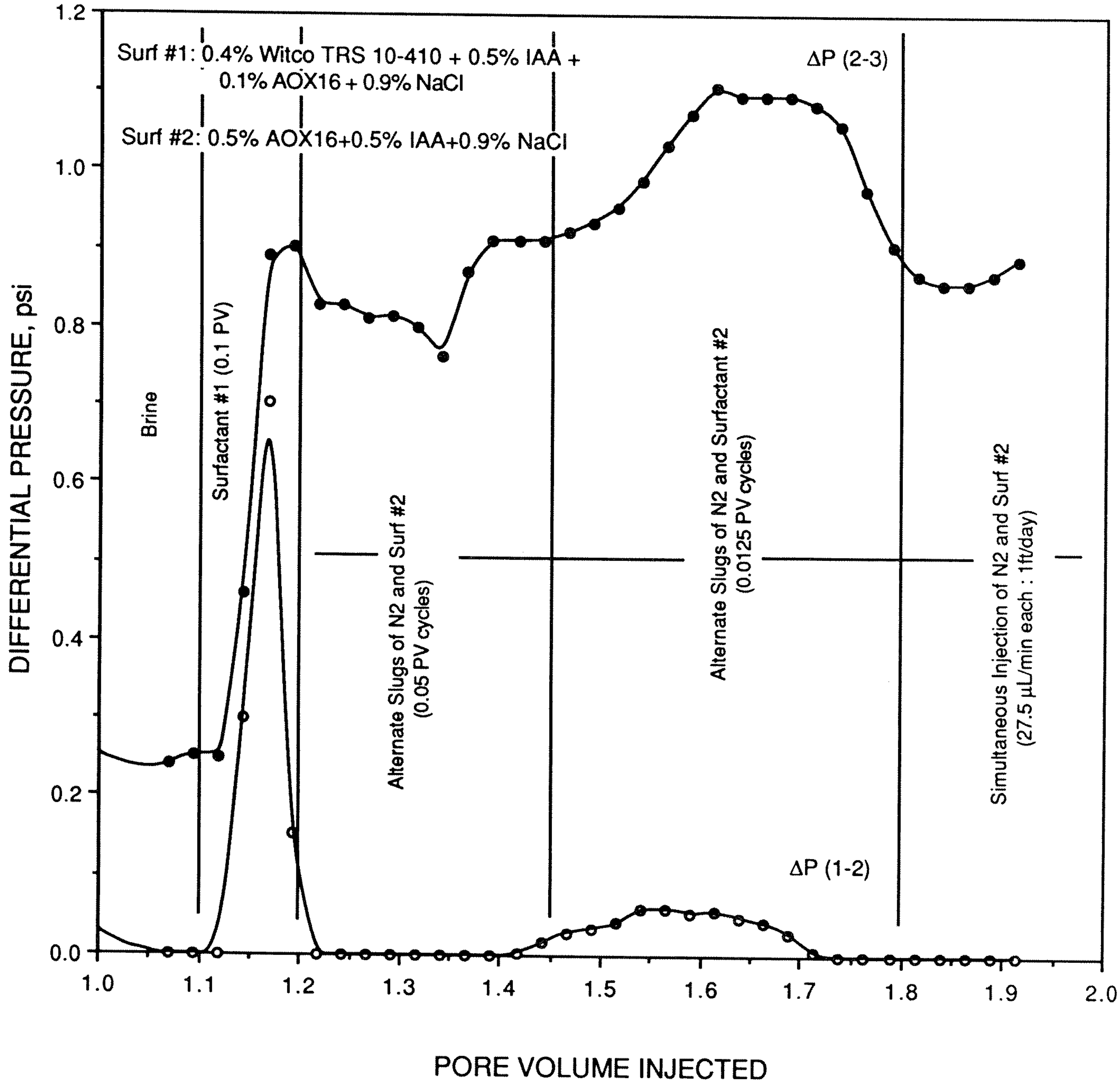

FIGURE 14. - Differential pressure profile of coreflood experiment no. 3.

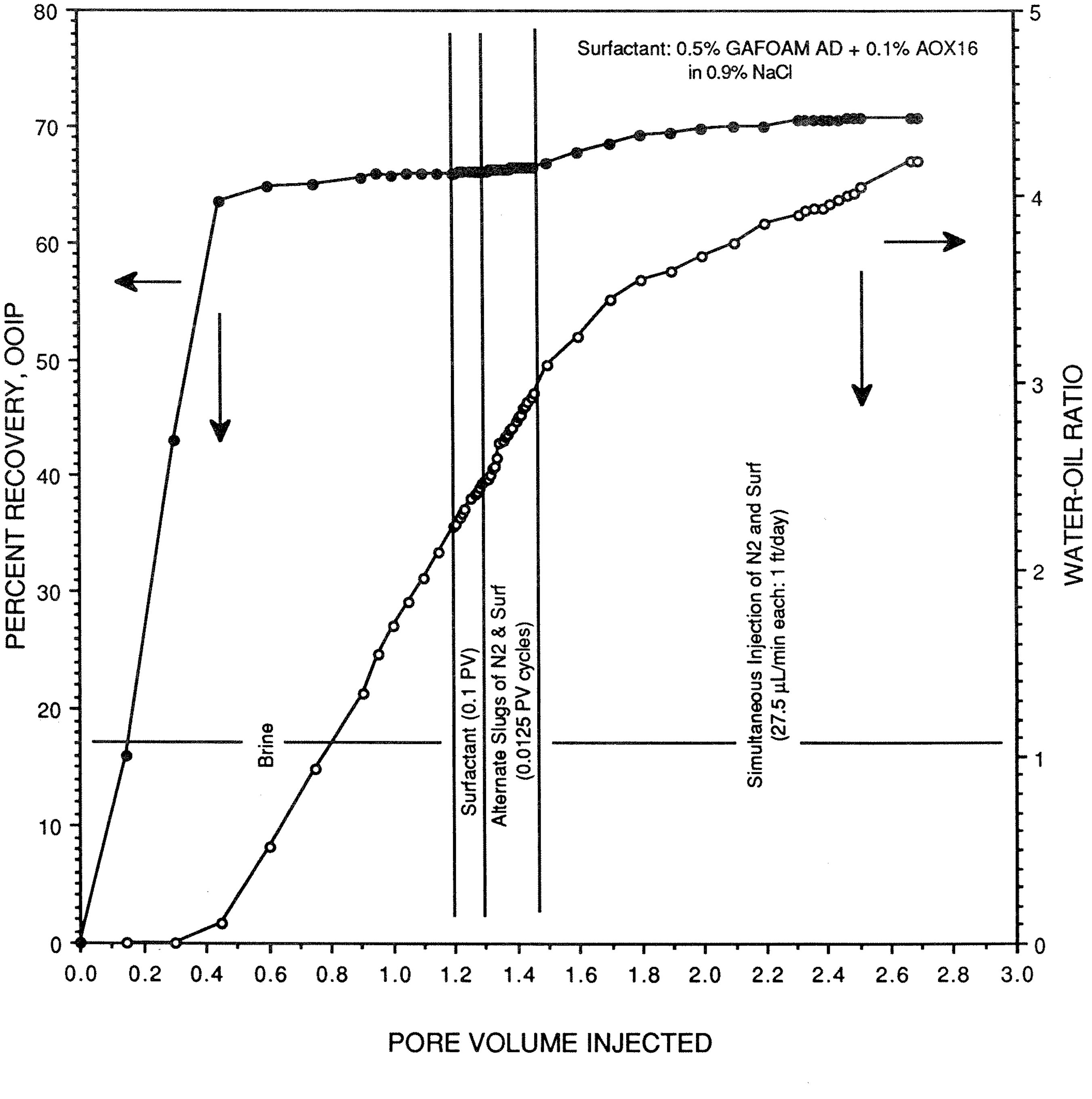

FIGURE 15. - Results of coreflood experiment no. 4.

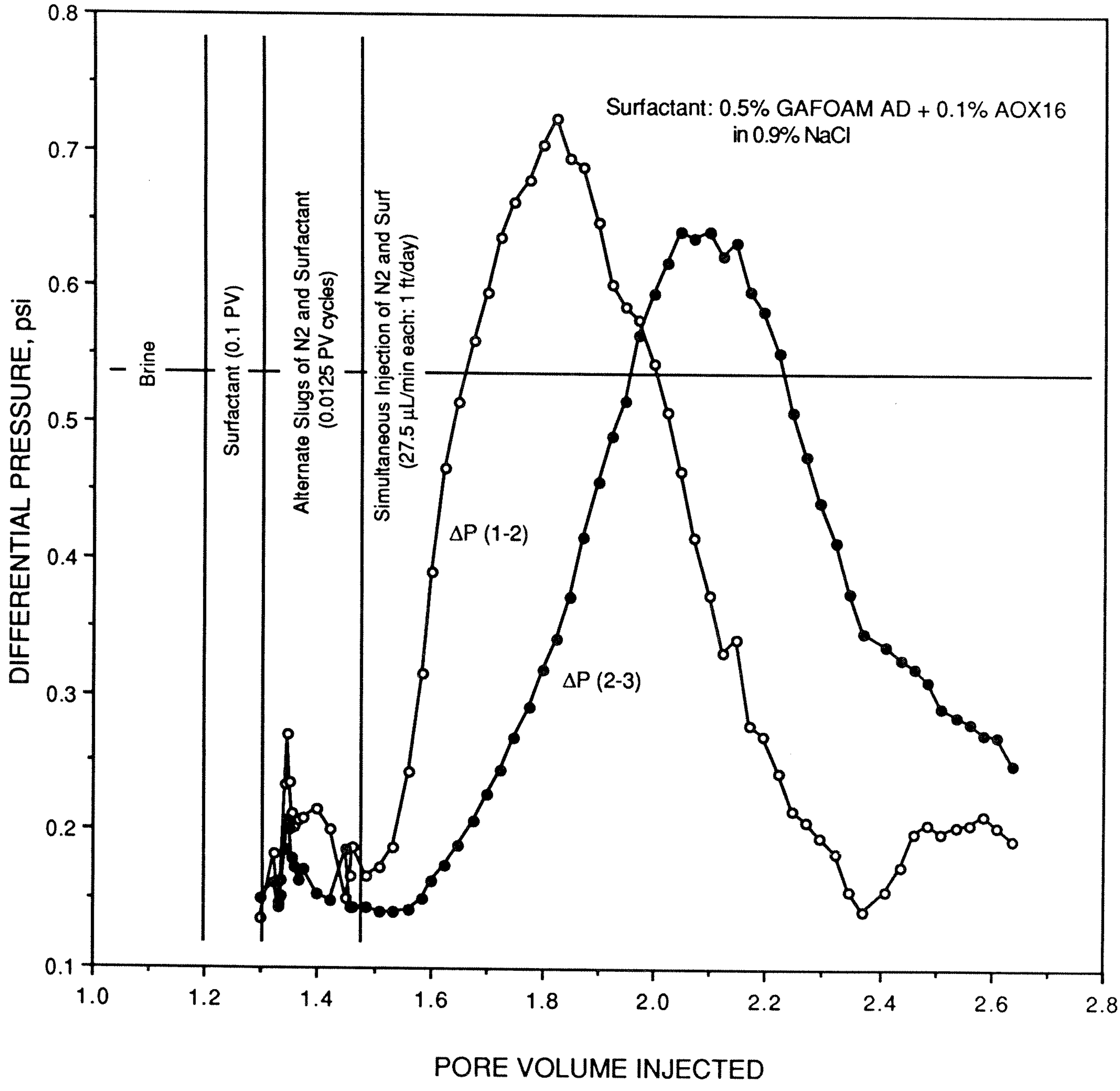

FIGURE 16. - Differential pressure profile of coreflood experiment no. 4.

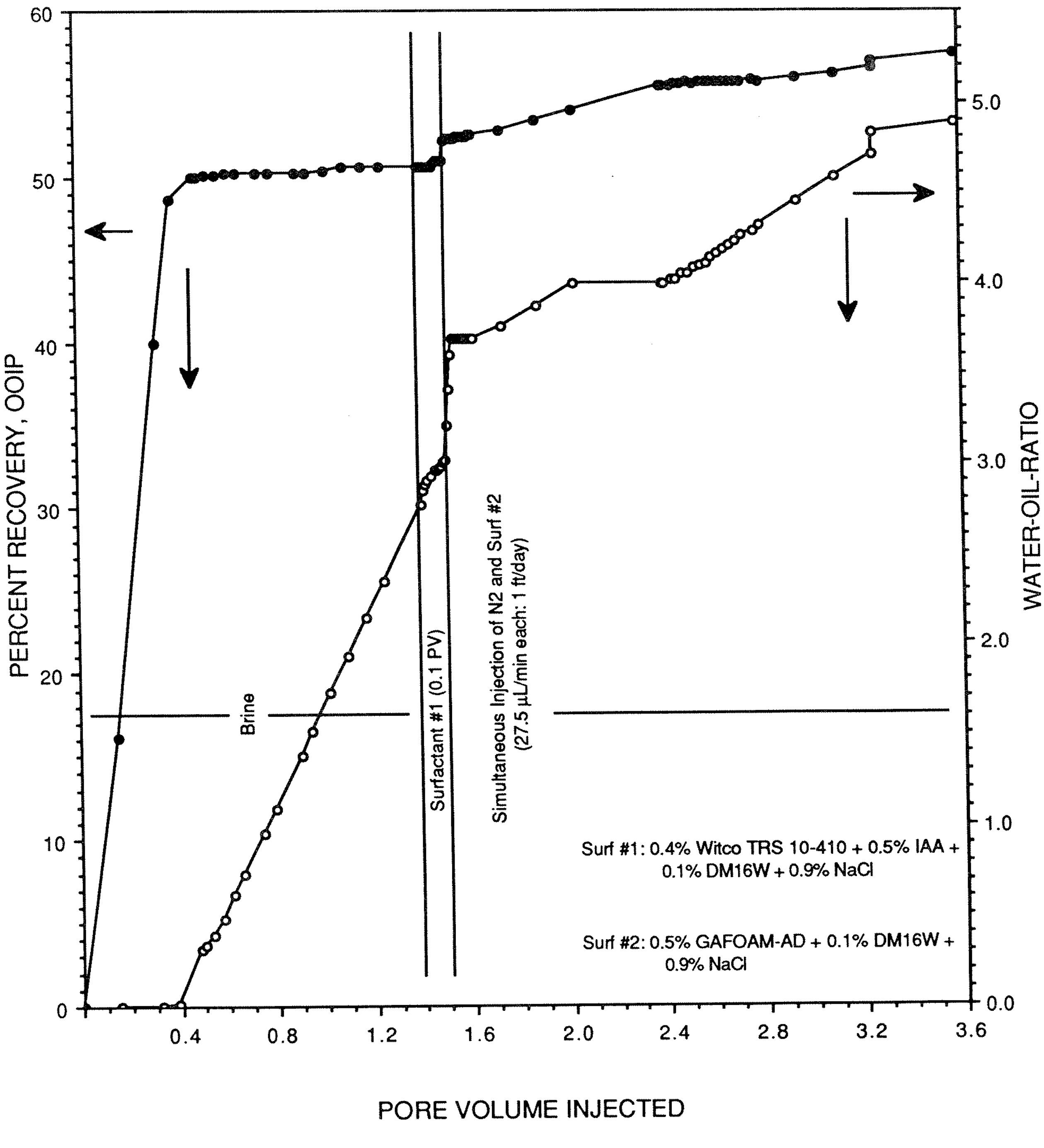

FIGURE 17. - Results of coreflood experiment no. 5.

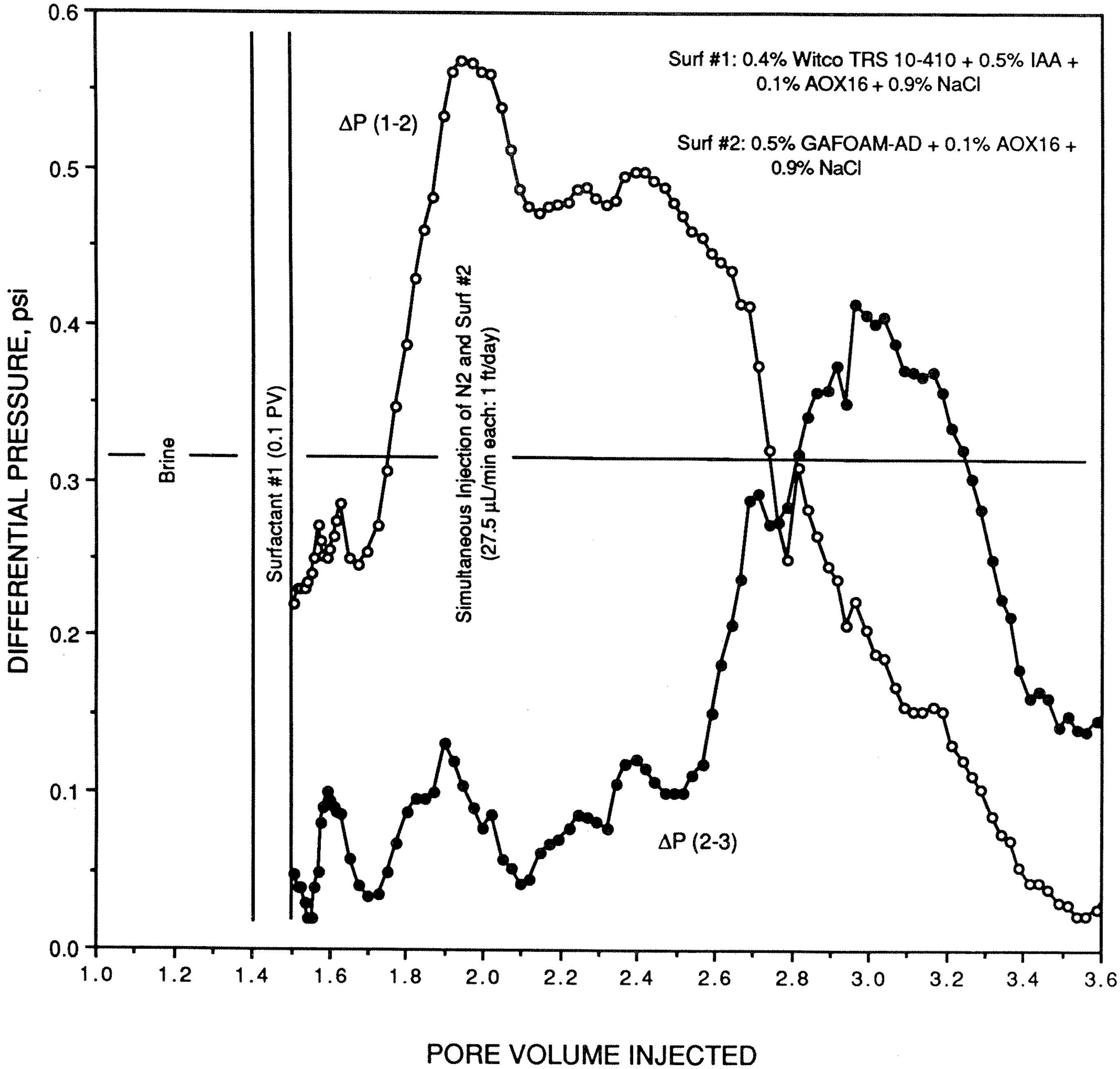

FIGURE 18. - Differential pressure profile of coreflood experiment no. 5.

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